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THE UNIVERSITY OF ALBERTA

INVESTIGATION OF THE IMMISCIBLE DISPLACEMENT OF OIL BY IMPURE CARBON DIOXIDE/BRINE AT LOW PRESSURES

BY
TAI A. NGUYEN ©

A THESIS
SUBMITTED TO THE FACULTY OF GRADUATE STUDIES AND RESEARCH
IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE DEGREE
OF MASTER OF SCIENCE
IN
PETROLEUM ENGINEERING

DEPARTMENT OF MINING, METALLURGICAL AND PETROLEUM
ENGINEERING

EDMONTON, ALBERTA, CANADA
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DATE: November 20th, 1992

To My Family

for

Their Boundless Love and Support

ABSTRACT

This research was directed towards an investigation of the performance of the immiscible carbon dioxide WAG (Water-Alternating-Gas) process, which is believed to recover considerable amounts of moderately viscous oils from thin and deep formations, where the reservoir conditions do not favour the application of thermal recovery methods.

A new phase of experimental work was developed in an attempt to examine the field recovery mechanisms of the immiscible WAG displacement process, where sources of *pure* carbon dioxide are rare and impure carbon dioxide is used instead.

In this investigation, nitrogen-carbon dioxide mixtures with nitrogen concentrations from 5.0 to 30.0 mole%, in increments of 5.0 mole%, were used to represent the field impure carbon dioxide since nitrogen is the main contaminant. Other gases are present in very small amounts.

Experimental measurements of the diffusivity and solubility of pure and impure carbon dioxide in Aberfeldy oil showed that the diffusivity and solubility of carbon dioxide in oil drastically decreased with increasing nitrogen content of the mixture. This was found to produce an adverse effect on the immiscible carbon dioxide WAG process, viz. the oil recovery decreased.

The experimental results show that, for the field application of the immiscible carbon dioxide WAG process to be effective, the volume of nitrogen present in carbon dioxide should not exceed 15.0 mole%. A significant drop in oil recovery was observed when the nitrogen content exceeded 15.0 mole%.

The effect of carbon dioxide partial pressure in the nitrogen-carbon dioxide mixture on oil recovery was investigated. It was found that increasing the carbon dioxide partial pressure increased the recovery efficiency, based on the results obtained. Also, a few experiments were conducted to study the effect of carbon dioxide partial volume. Decreased recoveries were noted in these experiments.

The scaling-up of experimental results to the field scale to predict the field recovery demonstrated that a large volume of oil can be recovered in a short time by this process, under optimal conditions.

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NOMENCLATURE

$D_{gox}, D_{goy}, D_{goz}$	Dispersion Coefficient of Carbon Dioxide into Oil in x, y, z Directions (L^2t^{-1})
$D_{gwx}, D_{gwy}, D_{gwz}$	Dispersion Coefficient of Carbon Dioxide into Water in x, y, z Directions (L^2t^{-1})
D_o	Molecular Diffusion of Carbon Dioxide into Oil (L^2t^{-1})
g	Gravity Acceleration (Lt^{-2})
GOR	Gas-Oil Ratio (sm^3/sm^3)
h	Height of the System (L)
h_M, h_P	Height of Model and Prototype (L)
HCPV	Hydrocarbon Pore Volume (L^3)
$J(S_g)$, $J(S_g^*)$	Gas-Oil Leverett J-function (Dimensionless)
$J(S_w)$, $J(S_w^*)$	Oil-Water Leverett J-function (Dimensionless)
k	Absolute Permeability (L^2)
k_g, k_o, k_w	Effective Permeability to Gas, Oil, and Water (L^2)
$k_{rg}(S_g)$, $k_{rg}(S_g^*)$	Relative Permeability to Gas (Dimensionless)
$k_{ro}(S_g, S_w)$, $k_{ro}(S_g^*, S_w^*)$	Relative Permeability to Oil (Dimensionless)
$k_{rw}(S_w)$, $k_{rw}(S_w^*)$	Relative Permeability to Water (Dimensionless)
k_M, k_P	Absolute Permeability of the Model and Prototype (L^2)
L	Length of the System (L)
L_M, L_P	Length of the Model and Prototype (L)
M_{go}	Gas-Oil Mobility Ratio (Dimensionless)
M_{wo}	Water-Oil Mobility Ratio (Dimensionless)
MW_g	Molecular Weight of Carbon Dioxide (MM^{-1})
MW_o	Molecular Weight of Oil (MM^{-1})
N_{cgo}	Linear Gas-Oil Capillary Number (Dimensionless)
N_{cow}	Linear Oil-Water Capillary Number (Dimensionless)
$\vec{N}_{gog}$	Vector of Oil-Gas Gravity Number (Dimensionless)
$\vec{N}_{gwo}$	Vector of Water-Oil Gravity Number (Dimensionless)
p	Pressure $(ML^{-1}t^{-2})$
Q_{prod}	Cumulative Production (L^3)

S_g, S_o, S_w	Gas, Oil, and Water Saturations (L^3L^{-3})
S_g^*, S_o^*, S_w^*	Normalized Gas, Oil, and Water Saturations (L^3L^{-3})
S_{oi}	Initial Oil Saturation (L^3L^{-3})
S_{wc}	Connate Water Saturation (L^3L^{-3})
S_{wi}	Initial Water Saturation (L^3L^{-3})
t	Time (t)
$t_{g,Field}$	Field Carbon Dioxide Injection Time (t)
$t_{w,Field}$	Field Water Injection Time (t)
$t_{total,Field}$	Field Total Injection Time (t)
T	Temperature (T)
$\vec{v}_T$	Vector of Superficial Velocity (Lt^{-1})
$\lvert\vec{v}_T\rvert, v$	Superficial Velocity (Lt^{-1})
V_g^*	Slug Volume of Carbon Dioxide $\left(L^3L^{-3}\right)$
V_w^*	Slug Volume of Water $\left(L^3L^{-3}\right)$
w	Width of the System (L)
W_g	Mass Injection Rate of Carbon Dioxide (Mt^{-1})
W_w	Mass Injection Rate of Water (Mt^{-1})
x_{CO_2}	Mole Fraction of Carbon Dioxide in the Oil-Carbon Dioxide Mixture (Fraction)
x_o	Mole Fraction of Oil in the Oil-Carbon Dioxide Mixture (Fraction)
x, y, z	Cartesian Coordinates
$\mathcal{M}$	Morphology Factor
$\Delta C/\Delta L$	Concentration Gradient of Carbon Dioxide in the Oil (ML^{-4})
$\Delta G/\Delta t$	Molar Flux of Carbon Dioxide by Diffusion (Mt^{-1})
$\Delta\rho_{og}$	Oil-Carbon Dioxide Density Difference (ML^{-3})
$\Delta\rho_{wo}$	Water-Oil Density Difference (ML^{-3})
μ_g, μ_o, μ_w	Carbon Dioxide, Oil, and Water Viscosities ($ML^{-1}t^{-1}$)
ρ_g, ρ_o, ρ_w	Carbon Dioxide, Oil, and Water Densities at Reservoir Conditions (ML^{-3})
σ	Interfacial Tension $\left(Mt^{-2}\right)$
ϕ	Porosity $\left(L^3L^{-3}\right)$
υ_f	Specific Volume of the Oil-Carbon Dioxide Mixture (L^3M^{-1})
υ_{CO_2}	Specific Volume of Carbon Dioxide (L^3M^{-1})
υ_o	Specific Volume of Oil (L^3M^{-1})

ϕ	Porosity $\left(L^3L^{-3}\right)$
k_{gR}	Reference Absolute Carbon Dioxide Permeability
p_{gR}	Reference Carbon Dioxide Pressure
S_{oR}	Reference Oil Saturation
ϕ_R	Reference Porosity

CHAPTER 1

INTRODUCTION

The immiscible carbon dioxide WAG (Water-Alternating-Gas) displacement process is being used increasingly as an enhanced oil recovery technique. Within the last decade, many studies have been conducted to examine the effectiveness of the process, as well as its mechanism. In the United States, many field studies and projects have been conducted with good results[1,2]. In Hungary, this method has been in use for thirty years to recover oil, and excellent oil recoveries have been reported[3]. In Alberta, the start of the commercial immiscible carbon dioxide project in Retlaw, in January 1991, marked the success and effectiveness of this method in recovering medium gravity heavy oils. The cumulative production, as reported in June 1991, exceeded 120,000 standard cubic meters[4]. It has also been shown that, based on laboratory and field studies, this method works much better than any other thermal recovery method in moderately viscous oil reservoirs where the formations are thin (less than 10 m) and the reservoir depths are large (greater than 1000 m).

In Alberta and Saskatchewan, there are many moderately viscous heavy oil reservoirs where the reservoir conditions fall in these regions. Moreover, many of them are underlain by bottom water zones. This makes the application of thermal recovery methods very inefficient and uneconomical due to excessively high heat loss to the bottom water zone and the resulting high operating costs. An alternative is to employ the immiscible carbon dioxide WAG method, which involves the injection of small slugs of carbon dioxide alternating with water.

Laboratory studies on the application of the immiscible WAG process to the recovery of oil from such reservoirs conducted by the previous reseachers[5-12] showed that this process can recover a substantial volume of oil, about 10 to 30% incremental oil compared to a waterflood, when pure carbon dioxide is used. On the other hand, the process is ineffective and recovers as much oil as a waterflood when pure nitrogen is used in place of carbon dioxide. For the field application of the process, pure carbon dioxide is rarely available since it is always mixed with contaminant gases such as nitrogen, oxygen, hydrogen sulphide, methane, ethane, etc. Nitrogen makes up the largest percentage of the contaminant gases present, the others being often negligible in comparison. Consequently, it is important to examine the effect of nitrogen on the immiscible carbon dioxide WAG process for practical applications.

This study is a contribution to the investigation of the field application of the immiscible WAG process where nitrogen-carbon dioxide mixtures are used. Specifically, it examines the effect of the presence of nitrogen in the carbon dioxide stream on the process mechanisms and recovery efficiency.

CHAPTER 2

STATEMENT OF THE PROBLEM

The objectives of this study were directed toward investigating the application of impure carbon dioxide containing nitrogen as the contaminant gas in place of pure carbon dioxide in the immiscible WAG process, and the results obtained were then compared with those obtained in the previous studies, to determine the effect of nitrogen on the process efficiency. The objectives can be summarized as follows:

1. To investigate the effect of nitrogen gas present with carbon dioxide on the immiscible carbon dioxide displacement mechanisms by measuring the solubility and diffusivity of nitrogen-carbon dioxide mixtures into a crude oil.

2. To conduct a series of experiments in a linear flow model utilizing impure carbon dioxide to study the effect of the presence of nitrogen on the immiscible carbon dioxide WAG process.

3. To study the effects of nitrogen/carbon dioxide partial pressure and volume.

4. To repeat selected linear model experiments in the two-dimensional model to examine the effect of nitrogen on the immiscible process displacement efficiency.

5. To compare the results obtained utilizing impure carbon dioxide with those utilizing pure carbon dioxide and pure nitrogen to determine the effect of gas mixture composition on oil recovery.

6. To scale up the experimental results to predict the field performance of the process.

CHAPTER 3

REVIEW OF THE LITERATURE

Beeson and Ortloff[13], Dickerson and Crawford[14], Welker and Dunlop[15], and Holm[16] pioneered the potential use of carbon dioxide as an enhanced oil recovery agent in the early 1960's. Holm and Josendal[17] conducted a laboratory study on the displacement of oil by carbon dioxide. They found that using carbon dioxide to displace oil under miscible conditions could recover up to 95% of the in-place oil. However, at the time, due to relatively high primary oil production and the very high cost of carbon dioxide compared to the price of oil, the use of carbon dioxide in enhancing oil recovery was not attractive to most oil companies. Today, due to low primary oil production and sources of carbon dioxide available at low prices around the globe, there is an increasing emphasis on using carbon dioxide as an enhanced oil recovery agent.

The objective of this chapter is to review the work done by many investigators in the past to investigate the displacement of oil by carbon dioxide.

3.1 Mechanisms of Oil Displacement by Carbon Dioxide

Basically, there are two types of displacement of oil by carbon dioxide: miscible and immiscible. Stalkup[18] described miscible carbon dioxide displacement as the process in which carbon dioxide completely mixes with oil in all proportions and all mixtures remain a single phase, i.e., there are no interfaces. Holm and Josendal[17] discovered that there are basically two types of mass transfer taking place during the development of miscibility between carbon dioxide and oil: the extraction of C_5 to C_{30} hydrocarbons from the in-place oil by carbon dioxide and the dissolution of carbon dioxide in the in-place oil. Miscible carbon dioxide displacement takes place only at high pressures. The pressure required for this type of displacement is above 7.5 MPa. For heavy oil reservoirs, where the reservoir pressures are low, the process is largely inapplicable.

In contrast to the miscible carbon dioxide displacement, the immiscible carbon dioxide displacement is invariably carried out at much lower pressures, making this process suitable for heavy oil reservoirs. The process is characterized by viscous, capillary, gravitational, diffusive, and inertial forces which dominate the displacement. Since laminar flow of carbon dioxide is likely to occur in unconsolidated sand reservoirs at low or moderate superficial velocities, the influence of inertial forces is not significant and thus can be neglected[19]. Flock, Peters, Baird, Wiborg and Kloepfer[20] pointed out that, in dealing with highly viscous oil displacement from unconsolidated sands, oil recovery is a weak function of the capillary forces. As such, only three forces - viscous, gravitational, and diffusive - control the immiscible carbon dioxide displacement process.

Work by Craig, Sanderling, Moore, and Geffen[21] showed that, for high mobility ratios, the volumetric sweep efficiency is low and varies little with the ratio of gravitational to viscous forces. Rojas[5,6] found that the diffusive forces could overcome the gravitational forces. Rojas and Farouq Ali[19] also found that even though the molecular diffusion of carbon dioxide in oil was high, it was not high enough to mobilize appreciable amounts of oil from uninvaded zones. Therefore, viscous forces are likely to dominate a carbon dioxide flood. Furthermore, they also documented the mechanisms of the immiscible carbon dioxide flooding process, stating that oil expansion, viscosity reduction, interfacial tension reduction leading to the formation of water-in-oil emulsions, and blowdown recovery were the four mechanisms that contributed to increased oil recovery from unconsolidated sands.

3.2 Transport Properties of Carbon Dioxide in Heavy Oil

3.2.1 Physical Properties of Carbon Dioxide

Carbon dioxide is known as a stable molecule where one atom of carbon is bonded to two atoms of oxygen. Its basic physical constants are as follows:

Molecular weight = 44.01 g/mol.
Critical temperature = 31°C.
Critical pressure = 7.40 MPa.
Critical volume = 0.0022 m^3/kg.

At atmospheric conditions, carbon dioxide is a relatively dense gas, about 50.0% heavier than air at atmospheric conditions. Its viscosity depends strongly on pressure and temperature. The viscosity of pure carbon dioxide at various pressures and temperatures can be found in Ref. 22. Other investigators[23] noted that carbon dioxide is more viscous than methane, ethane, propane, and hydrogen sulphide, but less viscous than air and nitrogen at any given temperature.

3.2.2 Solubility of Carbon Dioxide in Oil and Water

The solubility of carbon dioxide is the most important effect in the immiscible displacement of oil by carbon dioxide gas since it is theorized that among other mechanisms, an increase in the carbon dioxide solubility in oil leads to an increase in oil recovery because the oil phase left behind contains more carbon dioxide and less oil.

Early work in 1926 by Beecher and Parkhurst[24] showed that carbon dioxide was more soluble on a molar basis in a 30.2°API oil than air and natural gas. Svreck and Mehrotra's data[25] also showed that, among the three gases: carbon dioxide, methane, and nitrogen, carbon dioxide is the most soluble and nitrogen the least soluble in bitumen.

The solubility of carbon dioxide in oil is governed by the saturation pressure, reservoir temperature, composition of the oil and purity of the gas. Miller and Jones[26] and Chung, Jones, and Nguyen[27] measured the solubility of carbon dioxide in Canyon and Wilmington heavy oils and found that the solubility of carbon dioxide in heavy crude oils increased with pressure but decreased with temperature and reduced API gravity. Later, Sayegh and Sarbar[28] established that carbon dioxide is more soluble in oil at lower temperatures than at higher ones. Patton, Coats, and Spence[29], Holm and Josendal[17], and Chung et al[27] showed that the solubility of carbon dioxide reduced with the presence of methane in oil since carbon dioxide had to displace methane before dissolving in oil. Holm and Josendal[17] also mentioned that carbon dioxide did not displace all of the methane when it came into contact with oil. Spivak and Chima[30] noted that the solubility of pure carbon dioxide in oil was higher than that of a carbon dioxide-nitrogen mixture. Monger[31] also found that the presence of nitrogen in carbon dioxide had an adverse effect on the solubility of carbon dioxide in oil, while the presence of sulfur dioxide increased the carbon dioxide solubility.

Several investigators[32-36] have already presented correlations or methods to predict the solubility of carbon dioxide in oil. Simon and Graue[32] presented empirical correlations for carbon dioxide solubility in oil in 1965. Recently, Jamaluddin, Kalogerakis, and Chakma[36] have presented a method to estimate the solubility of carbon dioxide in heavy oils and bitumen. Their correlation is based on the Martin equation of state.

Carbon dioxide is also soluble in water. Its solubility in water is a function of salinity, pressure, and temperature. Steward and Munjal[37] conducted a study on the solubility of carbon dioxide in water. They found that carbon dioxide solubility decreased with increasing salinity and temperature.

The solubility of carbon dioxide in water influences the immiscible carbon dioxide process. Recently, Enick and Klara[38] demonstrated that the loss of carbon dioxide to water reduced oil recovery. Klins[39] recommended that for tertiary recovery projects the loss of carbon dioxide to water must be accounted for.

3.2.3 Diffusivity of Carbon Dioxide into Oil

Diffusion is another means of mass transfer between carbon dioxide and oil. It is the transport of mass due to random molecular motion and is independent of any convective forces in the system. Unlike solution, diffusion increases with increasing temperature[19].

According to Grogen and Pinczewski[40], molecular diffusion is considered to be important in the recovery of residual oil at the pore level since it is an important rate controlling mechanism in the carbon dioxide flood. Several authors[19,40,41,42] have pointed out the advantages of diffusion. It helps carbon dioxide to penetrate oil, inhibit viscous fingering, delay gas breakthrough and increase the oil rate.

Many efforts have been made by several investigators[43-45] to determine the molecular diffusion coefficient. McManamey and Wollen[46] proposed an equation for estimating the diffusion coefficient of carbon dioxide in organic liquids at atmospheric conditions, as an inverse function of oil viscosity. Later, Denoyelle and Bardon[47] pointed out that the diffusion coefficient of carbon dioxide increased with increasing pressure. Furthermore, other researchers[47-49] also noted that the diffusivity of carbon dioxide in oil at reservoir conditions was about five times higher than that noted by McManamey and Wollen[46]. Schmidt[50] proposed an equation for predicting the diffusion coefficients of carbon dioxide into bitumen at a constant pressure of 5 MPa. The equation is as follows:

$$\frac{D_{AB}\mu_B^{0.16}}{T} = 2.04 \times 10^{-12} \text{ m}^2\text{-Pa/K}$$

where

D_{AB} = diffusion coefficient (m^2/s)
μ_B = bitumen viscosity (Pa.s)
T = temperature (K)

This correlation illustrates that at a certain temperature the diffusivity of carbon dioxide depends on oil viscosity. This agrees with the observation of Grogen and Pinczewski[44], who previously showed that the carbon dioxide solubility in crude oils at reservoir conditions was dependent primarily on the solvent viscosity.

Reported data[46,47] indicate that the diffusion of carbon dioxide into oil is slower than the diffusion of carbon dioxide into water if the oil viscosity is above 0.5 mPa.s. Denoyelle and Bardon[47] also found that the porous medium had no effect on molecular diffusion because of the large pore scale as compared to the molecular scale and that for a porous medium saturated with both oil and water the diffusion of carbon dioxide was a linear function of water saturation.

In addition, the presence of a contaminant gas in carbon dioxide affects the diffusion rate of carbon dioxide into oil. Recently, a study on the diffusion of a 10 mole% nitrogen-90 mole% carbon dioxide mixture in oil conducted by Lansangan and Smith[51] showed that the diffusion rate of carbon dioxide drastically decreased with the presence of nitrogen, which formed a stagnant phase through which carbon dioxide had to diffuse before contacting the oil. This lowered the interfacial equilibrium carbon dioxide concentration, decreasing the rate of mass transfer, even at low nitrogen concentrations.

3.2.4 Dispersion of Carbon Dioxide in Oil

Additional mixing of fluids will take place due to the movement of fluids through a porous medium. Such mixing caused by fluid flow or concentration gradients resulting from fluid flow is known as dispersion, which is greater than that due to diffusion alone[41]. For heavy oils, the dispersion is too low; therefore, it cannot damp out the carbon dioxide fingers in immiscible displacement of oil by subcritical carbon dioxide dominated by viscous forces.[19]

3.3 Influence of Carbon Dioxide on Reservoir Fluids and Formation Properties

3.3.1 Swelling of Oil

Carbon dioxide swells oil when it comes into contact with the oil. The amount of swelling depends on the solubility of carbon dioxide. Several authors[27,31,32] defined the swelling factor as:

$$\text{Swelling Factor} = \frac{\text{Volume of } CO_2 \text{ - Saturated Oil @ p \& T}}{\text{Volume of Oil Without } CO_2 \text{ @ Atmospheric p \& T}}$$

For light oils, it was found that swelling increased rapidly with pressure at first before flattening out and then decreasing due to the extraction of lighter hydrocarbons into the carbon dioxide-rich gaseous phase[17]. For heavy oils, because of the absence of light hydrocarbons, Miller and Jones[26] and Chung et al.[27] found that the swelling factor responded linearly to the solubility of carbon dioxide in oil.

Simon and Graue[32] pointed out that the swelling factor was a function of the dissolved carbon dioxide volume and the size of the oil molecules. Miller and Jones[26] and Chung et al.[27] established that swelling was directly related to the carbon dioxide solubility.

The presence of a second gas in carbon dioxide is believed to affect the swelling of oil due to carbon dioxide. Monger[31] showed that nitrogen in carbon dioxide reduced swelling while sulfur dioxide increased swelling.

The role of oil swelling in enhanced oil recovery is very important. Rojas[5] confirmed that the greater the swelling, the less is the volume of oil left in the reservoir.

3.3.2 Viscosity Reduction

Reduction of oil viscosity is the most important effect of carbon dioxide when it dissolves in crude oil. Viscosity reduction depends mainly on the carbon dioxide solubility in oil, which is a function of temperature, pressure, and oil composition. Miller and Jones[26] and Chung et al.[27] reported that the oil viscosity significantly decreased when it was saturated with carbon dioxide. For instance, at 6.8 MPa, Miller and Jones[26] noted that the viscosity of a 1200 mPa.s oil saturated with carbon dioxide was 50 mPa.s. Jha[52] observed a 45 fold viscosity reduction (1430 mPa.s to 32 mPa.s) for the Lloyminster heavy oil with carbon dioxide at 7.55 MPa. Twenty fold oil viscosity reductions are very common[53]. In general, the more viscous the crude is, the more pronounced the viscosity decrease will be. Chung et al.[27] illustrated that the viscosity reduction when saturating crude oil with carbon dioxide and pressure above 6.8 MPa was more than that due to heating from 60°C to 90°C. Besides, Miller and Jones[26] reported that increasing the temperature increased the viscosity reduction with carbon dioxide in oil.

The viscosity reduction is influenced by the equilibrium time also. After the equilibrium time, there is no change in the viscosity of carbon dioxide-oil mixture.

Carbon dioxide is more effective in reducing oil viscosity than other gases. The data presented by Svreck and Mehrotra[25] show that carbon dioxide reduces the bitumen viscosity more than methane and nitrogen. Spivak and Chima[30] noted that the presence of nitrogen in carbon dioxide lowered the viscosity reduction.

3.3.3 Interfacial Tension Reduction

When carbon dioxide mixes with crude oil, it causes a reduction in the interfacial tension of oil with water and pure carbon dioxide. Work by Breston and Macfarlane[54] showed that the interfacial tension between Bradford crude and water could be reduced from 28.8 to 18.1 mN/m at a carbonation pressure of 5.2 MPa. Rojas and Farouq Ali[19] also found that the interfacial tension between Aberfeldy crude and carbonated brine was reduced to 16 from 25 mN/m when the carbonation pressure of brine was increased from 0.1 to 5.5 MPa. They further indicated that the interfacial tension reduction promoted the formation of brine-in-oil emulsions which helped to improve oil recovery and consequently retarded the production of large volumes of water.

Bardon and Denoyelle[53] documented that the interfacial tension reduction was less important in heavy oils than in light oils, but it contributed to oil recovery.

3.3.4 Asphaltene Precipitation

Several authors[55,56] have described asphaltenes in different ways. Novasad and Costain[57] described asphaltenes as "molecular entities dissolved in oil as colloidal particles, or as a combination of both". Even though, they are described in different ways, their physical structure in crude oil remains the same.

Leontaritis, Amaefule, and Charles[58] noted that one problem encountered in carbon dioxide flooding is asphaltene precipitation. Asphaltene deposition reduces the effective hydrocarbon mobility by blocking the pore throats, altering the formation wettability from water-wet to oil-wet and increasing hydrocarbon viscosity by nucleating water in oil emulsions. Kokal, Najman, Sayegh, and George[59] also found that asphaltene deposition caused severe problems and affected the recovery and cost of petroleum production. Laboratory studies by Huang[60] demonstrated that an asphaltene content of 4.6% weight in oil can alter the wettability of a Berea core to oil-wet. Grogen and Pinczewski[44] observed that asphaltenes formed a highly resistive layer at the oil-water interface which greatly reduced the mass transfer rate. Asphaltene precipitation has been observed in the field. For instance, in the carbon dioxide flood pilot in the Midale unit in southeastern Saskatchewan, a large amount of solid asphaltene, wax, and trapped oil was collected in the wellbore equipment and downhole facilities[57]. The deposition of these undesirable solids affects the project economics because of flow impairment, production delays, and costly cleanup operations. Similar problems of solid deposition have also been experienced in many other gas injection projects[57].

According to Strausz[55], asphaltene precipitation occurred when the hydrocarbons and polar oil fraction lost their ability to disperse colloidally the asphaltene fraction. Leontaratis et al.[58] noted that asphaltene flocculation during enhanced oil recovery was due to a drop in the reservoir pressure below the pressure at which asphaltene flocculate and mixing of solvents with reservoir oil.

Several investigators[56,60-62] also noted that the factors that influence asphaltene flocculation are crude oil composition, pressure, temperature, and properties of asphaltenes and the solvent gas. Furh, Klein, Komishke, Reichert, and Ridley[63] conducted a study on the effect of carbon dioxide on asphaltene flocculation in Lloyminster heavy oil, showing that an increase in carbon dioxide solubility increased the tendency for asphaltene to flocculate from toluene solutions in heavy oil. It was also observed that increasing the temperature decreased the tendency for flocculation. Furh et al.[63] further noted that, for Lloyminster heavy oil, asphaltenes started to precipitate at pressures greater than 3.5 MPa without the addition of heptane.

The effect of asphaltenes on oil recovery has been investigated by Huang[60], who conducted a series of carbon dioxide core flood experiments at 49°C and 17.2 MPa using a 122 cm long Berea core. He concluded that oil recovery decreased with increasing asphaltene content or with increasing asphaltene deposition.

3.3.5 Permeability Change

According to Ellis[64], carbon dioxide dissolves in water forming hydrogen carbonate, which then dissociates to form carbonic acid. The chemical reaction can be summarized below.

$$CO_{2_g} \Leftrightarrow CO_{2_{aq}} + H_2O \Leftrightarrow H_2CO_{3_{aq}} \Leftrightarrow H^{+}_{aq} + HCO^{-}_{3_{aq}}$$

The carbonic acid will react with the carbonated portions of the rock, such as calcite. The reaction can be described as follows:

$$H^{-}_{aq} + HCO^{-}_{3} + CaCO_{3_s} \Leftrightarrow Ca^{2+}_{aq} + 2\left(HCO^{-}_{3}\right)_{aq}$$

The equilibrium of these two reactions depends on the concentrations of reactants and products, pressure, and temperature.

The rock permeability changes as a result of the above reactions: Holm[16] noted a three fold increase in the permeability of a dolomite core after 0.7 PV of carbon dioxide and 8 PV of carbonated water had been injected. He concluded that in field applications of carbon dioxide the permeability would be increased in the vicinity of injection wells.

Omole and Osolar[65] pointed out the effect of carbon dioxide on carbonated rocks. They stated that carbon dioxide dissolved part of the rock around the injection well during carbon dioxide flooding of carbonate reservoirs. Depending on the pressure drop, the precipitation of dissolved carbonate along the flow path would occur. The greater the pressure drawdown, the greater will be the carbonate precipitation and consequently the reduction in the formation rock permeability. This negative effect was noted by other investigators as well[19,66].

Swartwout and Ho[67] further confirmed that the dissolution of carbon dioxide gas in brine lowered the pH of the brine and that the formation of carbonates depended on the pH of the brine. The precipitation of carbonate can be detrimental to the formation permeability and scale can lead to malfunction of equipment and promote corrosion.

3.4 Immiscible Carbon Dioxide/Water Injection Strategies

Basically, there are six different immiscible carbon dioxide processes that have been suggested. They are carbonated water (brine) injection, continuous carbon dioxide gas injection, carbon dioxide slug process, simultaneous injection of carbon dioxide and water, alternate injection of slugs of carbon dioxide and water (WAG), and carbon dioxide huff 'n' puff. These are discussed below.

3.4.1 Carbonated Water Injection

The basic idea of carbonated water injection is to saturate water with carbon dioxide, and then inject the carbon dioxide-water mixture into the reservoir. This process was investigated in the early 60's by Holm[16] and Saxon, Breston, and Macfarlane[68] and in the early 70's by De Nevers[69]. They all concluded that the method failed to improve recovery. Saxon et al.[68] stated that carbonated water flood was no better than an ordinary waterflood. The reasons for the lack of effectiveness of this process in enhancing recovery are as follows. First, the diffusion process is very slow since carbon dioxide must diffuse out of water before contacting the reservoir oil. Second, since the diffusion is slow, an effective carbon dioxide concentration at the flood front is absent. Third, because of the low rate of viscosity reduction, adverse mobility ratios will continue to exist during the flood.

Another problem associated with this process is severe corrosion of the injection facilities due to the carbonic acid.

Recently, carbonated water imbibition studies conducted on core plugs at 13.8 MPa by Perez, Poston, and Sharif[70] showed that this method may work in fractured, low matrix permeability, and low gas-oil ratio oil reservoirs.

3.4.2 Continuous Carbon Dioxide Gas Injection

Continuous injection of carbon dioxide until the producing economic gas-oil ratio is reached is known as continuous carbon dioxide gas injection process. This process is impractical due to the lack of mobility and gravity control which leads to poor sweep and low recovery. Furthermore, since carbon dioxide bypasses much of the oil, a large volume of carbon dioxide is required to produce one standard cubic metre of oil. Experiments conducted in a scaled two-dimensional model by Rojas[5] illustrated that carbon dioxide requirement for this process is about ten times greater than that for the WAG process. Carbon dioxide requirement is defined as the volume of carbon dioxide required to produce one volume of oil. Sayegh and Maini[71] conducted experiments in a linear core utilizing continuous injection of carbon dioxide and found that the recovery was only 3.0% of Lloyminster crude oil at carbon dioxide breakthrough.

3.4.3 Carbon Dioxide Slug Process

In the carbon dioxide slug process, a pre-determined volume of carbon dioxide is injected and then followed by continuous injection of water to drive the carbon dioxide slug. Carbon dioxide gas is immiscibly displaced by the water, leaving a residual carbon dioxide saturation in the reservoir. Rojas[5] reported low recoveries when using this method to displace oil in a scaled two-dimensional model.

3.4.4 Simultaneous Carbon Dioxide and Water Injection

Simulation studies of the simultaneous carbon dioxide and water injection process were performed by Warner[72], who noted that simultaneous injection of carbon dioxide and water could yield a high oil recovery. However, there are a number of problems associated with this process. They are dual completion and operating costs, reduced injectivities of the injected fluids, and severe corrosion of the injection equipment.

3.4.5 Alternate Injection of Slugs of Carbon Dioxide and Water (WAG)

The alternate injection of slugs of carbon dioxide and water process consists of injecting slugs of carbon dioxide alternated with slugs of water until the desired volume of carbon dioxide has been injected. It is then followed by continuous injection of water until the economic water-oil-ratio is reached. Several researchers[5-7,16,19,73] have found that this process is very successful in reducing carbon dioxide mobility and promoting the mixing of carbon dioxide with oil and more uniform distribution of carbon dioxide throughout the reservoir, which therefore leads to an effective sweep.

Rojas and Farouq Ali[5,6] conducted experiments utilizing the immiscible carbon dioxide WAG process in a scaled two-dimensional model. They showed that a total carbon dioxide volume of 20% HCPV and a 4:1 WAG ratio yielded the highest recovery. The WAG ratio is the ratio of the volume of water to that of carbon dioxide at reservoir conditions. It was also shown that this process could be economical in producing oil since the carbon dioxide requirement was the lowest compared to the other four processes mentioned previously.

3.4.6 Carbon Dioxide Huff 'n' Puff Process

The immiscible carbon dioxide huff 'n' puff process[1] appears to be gaining popularity due to their relatively quick pay out nature. The process is very similar to the cyclic steam stimulation. It consists of injecting large volumes of carbon dioxide down a producing well and shutting in the well for a few weeks to allow carbon dioxide to soak (soak period). After this soak period, the well is returned to production. The mobilized oil is driven to the well by the driving force exerted by the released gas. The producing life of the process is limited to two to three cycles. The efficiency of the process is measured by the volume of oil recovered per unit volume of carbon dioxide injected and also by the volume injected per metre of pay.

3.5 Use of Nitrogen-Carbon Dioxide Mixtures in the Immiscible Displacement Process

Studies conducted by Anada[74] to investigate the use of flue gas (containing nitrogen and carbon dioxide) showed that flue gas may be used in place of pure carbon dioxide for shallow heavy oil reservoirs. Anada also provided explanations on the phenomena that may occur when flue gas is used in place of pure carbon dioxide. He explained that while the carbon dioxide component of flue gas dissolved in oil to reduce oil viscosity, the nitrogen component provided the energy for driving the mobilized oil.

Spivak and Chima's simulation studies[30] showed that only a small volume of nitrogen in the 82 mole% carbon dioxide-18 mole% nitrogen mixture dissolved in Wilmington oil at 6.9 MPa and 49°C and that the viscosity reduction was less due to the decreased solubility of carbon dioxide in oil in the presence of nitrogen. They also noted that the gas breakthrough was earlier, the recovery was lower, and the compositional fronts were more dispersed as compared to those for pure carbon dioxide. They explained that nitrogen was essentially insoluble in oil and contributed to an increased free gas saturation at any point of injection.

Recently, the adverse effect of nitrogen has also been shown by the work of Fong, Tang, Emanual, and Sabat[75], who performed vertical core floods on a 21°API oil, utilizing flue gas typically containing 80 mole% nitrogen and 20 mole% carbon dioxide. They noted that the gas breakthrough was much earlier compared to that for pure carbon dioxide. The gas breakthrough occurred at 12% OOIP recovery compared to 45% OOIP recovery for pure carbon dioxide. Their work also showed that only 23% OOIP was recovered when using 80 mole% nitrogen-20 mole% carbon dioxide, as compared to 56% OOIP recovery obtained using pure carbon dioxide.

Dria, Pope, and Sepehrnoori[76] measured three-phase gas, oil, brine relative permeabilities in a carbonate core, and found that carbon dioxide had a lower relative permeability, total relative mobility, and injectivity than nitrogen and that the carbon dioxide-oil interfacial tension was about an order of magnitude lower than that for nitrogen and oil.

Mayer, Earlougher, Spivak, and Costa[77] conducted two groups of linear core experiments utilizing two types of gases. The first group was performed using pure carbon dioxide and a 13.5°API oil sample, and the second 84 mole% carbon dioxide-16 mole%

nitrogen mixture and a 12.3°API oil sample. The first group was conducted at 5.9 MPa while the second at 6.9 MPa, such that the partial pressure of carbon dioxide in the mixture was 5.9 MPa. Their data showed that the recoveries obtained from the two groups of experiments were similar. Based upon this, they concluded that the presence of the nitrogen did not appear detrimental to the recovery.

Based upon the findings by those researchers, it is necessary to know, for field application, what nitrogen concentration will start to have a detrimental effect on the process recovery. According to Kessel, Pusch, and Albertsen[78], in order for the process to be effective, concentration of nitrogen should not exceed about 15.0 mole%.

3.6 Physical Model Scaling Techniques

In general, there are two methods available for deriving the scaling groups: inspectional and dimensional analyses. Rojas[5,7] applied both methods to derive the scaling groups describing the immiscible displacement of oil by carbon dioxide and water.

Dimensional analysis, according to Langhaar[79], is "a method by which information about a phenomenon from the single premise that the phenomenon can be described by a dimensionally correct equation among certain variables". The method is based on the Buckingham π-theorem which uses the Principle of Similarity. It is used to derive dimensionless groups when the differential equations describing the flow process are not known. This method requires a knowledge of the relevant variables for the process prior to the actual analysis. These variables are combined and arranged in a set of dimensionless groups (π's). When all the groups in the set are independent of each other and every dimensionless group containing the same variables, not belonging to the set, can be formed by combining groups belonging to the set, the set is complete. The general rule for dimensional analysis is that if there are n separate variables and m primary quantities, then the set will be complete when there are (n-m) dimensionless groups. In general, dimensional analysis allows the derivation of scaling groups from variables that do not appear among those governing equations forming the basis for inspectional analysis.

Craig et al.[21] defined inspectional analysis as the process in which all partial differential equations describing the flow process mechanism are combined to form a single equation, and the coefficients of this equation are then combined to form the dimensionless scaling groups. The chief advantage of inspectional analysis over dimensional analysis is that the scaling criteria thus obtained have a clear physical meaning, and their function in the process can be visualized[5].

Geertsma, Croes, and Schwarz[81] pointed out that, in general, the set of scaling groups from dimensional analysis is larger than that from inspectional analysis. Kimber, Farouq Ali, and Puttagunta[82] used both dimensional and inspectional analyses to obtain the set of scaling criteria for steam and steam-additive injection experiments. They came up with the same conclusion as Geertsma et al. Farouq Ali, Donohue, and Stahl[83] also pointed out the advantages and disadvantages of the two techniques and difficulties in fabricating a properly scaled model.

As mentioned above, both methods were employed to derive the set of scaling groups. For inspectional analysis, the governing partial differential equations were derived based on various assumptions[5]. They included: homogeneous and isotropic porous medium; the fluids (oil and gas, water) are immiscible, of small and constant compressibility at reservoir conditions and follow Newtonian behaviour; Darcy's law applies to fluid flow (i.e. no inertial effect); Fick's law for diffusion is valid; relative permeabilities are functions of saturation, according to channel flow theory, i.e. pore size distribution, wettability, saturation history, and interfacial tension are constant in an isothermal displacement; constant temperature exists during carbon dioxide and water injection; instantaneous equilibrium exists in three phases (oleic, aqueous, and carbon dioxide); mass transfer between carbon dioxide-oil, and carbon dioxide-water takes place only by solution; and no transfer of oil or water into the carbon dioxide gas phase takes place.

Shown below is the scaling groups derived from dimensional and inspectional analyses.

For dimensional analysis, the scaling groups are as follows[5].

$$\frac{L}{w},\ \frac{L}{h},\ \frac{k_{rw}\left(S_w^*\right)\mu_o}{k_{ro}\left(S_g^*,S_w^*\right)\mu_w},\ \frac{k_{rg}\left(S_g^*\right)\mu_o}{k_{ro}\left(S_g^*,S_w^*\right)\mu_g},\ \frac{gk\Delta\rho_{og}}{v\mu_g},\ \frac{gk\Delta\rho_{wo}}{v\mu_w},\ \frac{\sigma_{go}\sqrt{k\phi}}{L\mu_g v},\ \frac{\sigma_{ow}\sqrt{k\phi}}{L\mu_w v},$$

$$\frac{D_{goy}L}{w^2 v},\ \frac{D_{gwy}L}{w^2 v},\ \frac{D_{goy}L}{D_{gox}w},\ \frac{D_{goz}L}{D_{gox}h},\ \frac{D_{gwy}L}{D_{gwx}w},\ \frac{D_{gwz}L}{D_{gwx}h},\ \frac{\rho_g v\sqrt{k}}{\mu_g},\ \frac{\rho_w v\sqrt{k}}{\mu_w},\ \frac{V_w^*}{V_g^*},\ \phi,\ \mathcal{M},$$

$$k_{rg}\left(S_g^*\right),\ k_{ro}\left(S_g^*,S_w^*\right),\ k_{rw}\left(S_w^*\right),\ J\left(S_g^*\right),\ J\left(S_w^*\right)$$

For inspectional analysis, the scaling groups are as shown[5].

$$\frac{L}{w},\ \frac{L}{h},\ M_{wo},\ M_{go},\ \vec{N}_{gog},\ \vec{N}_{gwo},\ N_{cgo},\ N_{cow},\ \frac{dJ\left(S_g^*\right)}{dS_g^*},\ \frac{dJ\left(S_w^*\right)}{dS_w^*},\ \frac{D_{gox}}{|\vec{v}_T|L},\ \frac{D_{gwx}}{|\vec{v}_T|L},\ \frac{D_{goy}L}{D_{gox}w},$$
$$\frac{D_{goz}L}{D_{gox}h},\ \frac{D_{gwy}L}{D_{gwx}w},\ \frac{D_{gwz}L}{D_{gwx}h}$$

A new set of scaling criteria for a more comprehensive description of the process, which accounts for diffusion, and partial phase equilibrium was also derived and presented by Lozada and Farouq Ali[84].

Table 3.1 compares the scaling groups derived by both inspectional and dimensional analyses.

Table 3.1 - Comparison of Scaling Groups Derived by Inspectional and Dimensional Analyses, after Rojas[5].

		Derived By		
Number	Scaling Group	Inspectional Analysis	Dimensional Analysis	Name
1	L/w	Yes	Yes	Geometric Factor
2	L/h	Yes	Yes	Geometric Factor
3	$\dfrac{k_{rg}(S_g^*)\mu_o}{k_{ro}(S_g^*,S_w^*)\mu_w}$	Yes	Yes	Gas-Oil Ratio of Viscous Forces
4	$\dfrac{k_{rw}(S_w^*)\mu_o}{k_{ro}(S_g^*,S_w^*)\mu_w}$	Yes	Yes	Water-Oil Ratio of Viscous Forces
5	$\dfrac{\vec{g}k\Delta\rho_{og}}{v\mu_g}$	Yes	Yes	Gas-Oil Ratio of Gravitational Forces to Viscous Forces
6	$\dfrac{\vec{g}k\Delta\rho_{wo}}{v\mu_w}$	Yes	Yes	Water-Oil Ratio of Gravitational Forces to Viscous Forces
7	$\dfrac{\sigma_{go}\sqrt{k\phi}}{L\mu_g v}$	Yes	Yes	Gas-Oil Ratio of Capillary Forces to Viscous Forces
8	$\dfrac{\sigma_{ow}\sqrt{k\phi}}{L\mu_w v}$	Yes	Yes	Water-Oil Ratio of Capillary Forces to Viscous Forces
9	$\dfrac{D_{goy}L}{w^2\lvert\vec{v}_T\rvert}$	Yes	Yes	Gas in Oil Transverse Dispersion Scaling Group (or Ratio of Convection Time to Transverse Dispersion Time)
10	$\dfrac{D_{gwy}L}{w^2\lvert\vec{v}_T\rvert}$	Yes	Yes	Gas in Water Transverse Dispersion Scaling Group (or Ratio of Convection Time to Transverse Dispersion Time)
11	$\dfrac{D_{goy}L}{D_{gox}w}$	Yes	Yes	x-y Gas in Oil Dispersion Similarity Group

Table 3.1 (Continued)

Number	Scaling Group	Derived By Inspectional Analysis	 Dimensional Analysis	Name
12	$\frac{D_{goz}L}{D_{gox}h}$	Yes	Yes	x-z Gas in Oil Dispersion Similarity Group
13	$\frac{D_{gwy}L}{D_{gwx}w}$	Yes	Yes	x-y Gas in Water Dispersion Similarity Group
14	$\frac{D_{gwz}L}{D_{gwx}h}$	Yes	Yes	x-z Gas in Water Dispersion Similarity Group
15	$\frac{\rho_g v\sqrt{k}}{\mu_g}$	No	Yes	Reynolds Number for Gas
16	$\frac{\rho_w v\sqrt{k}}{\mu_w}$	No	Yes	Reynolds Number for Water
17	$\frac{V_w^*}{V_g^*}$	No	Yes	Water-Gas Ratio of Slug Volumes
18	ϕ	No	Yes	Porosity Factor
19	$\mathcal{M}$	No	Yes	Morphology Factor
20	$k_{rg}\left(S_g^*\right)$	Yes	Yes	Gas Relative Permeability Factor
21	$k_{ro}\left(S_g^*,S_w^*\right)$	Yes	Yes	Oil Relative Permeability Factor
22	$k_{rw}\left(S_w^*\right)$	Yes	Yes	water Relative Permeability Factor
23	$J\left(S_g^*\right)$	No	Yes	Gas-Oil Leverett J-Function Factor
24	$J\left(S_w^*\right)$	No	Yes	Oil-Water Leverett J-Function Factor

Table 3.1 (Continued)

Number	Scaling Group	Inspectional Analysis	Derived By Dimensional Analysis	Name
25	$\frac{dJ\left(S_g^*\right)}{dS_g^*}$	Yes	No	Gas-Oil Leverett J-Function Slope Factor
26	$\frac{dJ\left(S_w^*\right)}{dS_w^*}$	Yes	No	Oil-Water Leverett J-Function Slope Factor

In practice, it is not practical to satisfy all the scaling groups involved in a recovery process. Furthermore, not all scaling groups are important for heavy oil recovery, and some of the scaling groups can be relaxed. For example, the ratio of capillary-to-viscous forces is low, and unscaled capillary pressures have little effect on oil recovery . Also, since laminar flow is likely to occur in unconsolidated porous media, it is unnecessary to consider the effect of inertial forces. Thus, these two effects were relaxed, and the number of scaling groups was reduced to thirteen[5,7]. These thirteen scaling groups were used to design and build the high pressure two-dimensional physical model. Table 3.2 presents the final thirteen scaling groups.

Table 3.2 - Scaling Groups After Relaxation, after Rojas[5].

No.	Scaling Group	Name
1	$\frac{L}{h}$	Geometric Factor
2	$\frac{L}{w}$	Geometric Factor
3	M_{go}	Mobility Ratio of the Viscous Forces of the Vapour and Oleic Phases
4	M_{wo}	Mobility Ratio of the Viscous Forces of the Aqueous and Oleic Phases
5	$\frac{\vec{g}k\Delta\rho_{og}}{v\mu_g}$	Ratio of Gravitational to Viscous Forces of the Oleic and Vapour Phases
6	$\frac{\vec{g}k\Delta\rho_{ow}}{v\mu_w}$	Ratio of Gravitational to Viscous Forces of the Oleic and Aqueous Phases
7	$\frac{V_w^*}{V_g^*}$	Ratio of Water to Gas Slug Volumes
8	$\frac{D_{Tgo}L}{w^2v}$	Ratio of Convective Time to Transverse Dispersion Time of the Vapour and Oleic Phases
9	$\frac{D_{Tgw}L}{w^2v}$	Ratio of Convective Time to Transverse Dispersion Time of the Vapour and Aqueous Phases
10	$\frac{D_{Tgo}L}{D_{Lgo}w}$	Gas-in-Oil Dispersion Similarity Group
11	$\frac{D_{Tgw}L}{D_{Lgw}w}$	Gas-in-Water Dispersion Similarity Group
12	ϕ	Porosity Factor
13	$\mathcal{M}$	Morphology Factor

Assuming that the prototype and model have the same morphology, fluids and are operated at the same temperature and pressure, the following equalities must be maintained.

$$\frac{\left(L/h\right)_M}{\left(L/h\right)_P} = \frac{\left(L/w\right)_M}{\left(L/w\right)_P} = \frac{\left(k/v\right)_M}{\left(k/v\right)_P} = \frac{\left(V_w^*/V_g^*\right)_M}{\left(V_w^*/V_g^*\right)_P}$$

These equalities allowed the selection of the model dimensions, injection rates, and the slug volumes of carbon dioxide and brine in order to obtain approximate similarity in recovery between the model and the prototype[5].

As for the partially scaled linear model, it was designed on the basis of the assumption that the rectangular cross-section can be approximated by a circular cross-section, as follows[9,10]:

$$d = 2\sqrt{\frac{hw}{\pi}}$$

The dimensions of the two-dimensional and partially scaled linear core models are given in Chapter 4.

The heavy oil field for which both models were scaled is the Aberfeldy field in Lloyminster. The properties of the reservoir are summarized in Table 3.3.

Table 3.3 - Reservoir and Fluid Properties of the Aberfeldy Field[80].

Horizontal unconsolidated marine sands.

Pattern	Five spot
Pattern size	64,570 m^2
Net sand thickness	6.1 m
Permeability	1-3 darcies
Porosity	35%
Depth	500-600 m
Temperature	23°C
Initial reservoir pressure	3.45 MPa
Present reservoir pressure	2.5 MPa
Oil density	0.953 g/cm^3 at 23°C
Oil gravity	15°API
Oil viscosity	1000 mPa.s
Original solution GOR	9 m^3/m^3
Water density	1.05 g/cm^3 at 23°C
Water viscosity	1.14 mPa.s
Initial oil saturation	87%
Initial gas saturation	13%
Interfacial tension/oil-water	25.5 mN/m

3.7 Review of The Experiments Conducted in Previous Studies

This part gives a brief review of the work done in the past. Specific details can be found in References 5 to 12. Table 3.4 provides a summary of the groups of experiments done by Rojas[5,6,7], Zhu[7,8], Dyer[9,10] and Prosper[11,12].

Rojas[5,6,7] conducted all of his experiments at 5.5 MPa in a two-dimensional model using different immiscible carbon dioxide/water injection strategies and found that immiscible carbon dioxide WAG gave the highest recovery. He also studied the effect of varying number of slugs and WAG ratio and found that ten pairs of slugs of carbon dioxide and water and a 4:1 WAG ratio yielded the highest recovery, and the recovery obtained was about 15% higher than that obtained from a waterflood. The effect of oil viscosity was examined as well. An increase in oil viscosity caused a decrease in recovery. He concluded that oil recovery was sensitive to the injection rates of carbon dioxide and brine. Low carbon dioxide gas and high brine injection rates produced the highest recovery.

Zhu[7,8] conducted experiments with pure carbon dioxide and nitrogen in the same two-dimensional model at 5.5 and 2.5 MPa. He noted that substitution of carbon dioxide by nitrogen gave the same recovery as a waterflood in a WAG type process, and that nitrogen breakthrough occurred immediately after injection. It was found out that an initial gas saturation could lead to a decrease in recovery, and a mobile gas phase could adversely affect the performance of the immiscible process. The effect of two types of reservoir heterogeneities was also investigated, noting that these heterogeneities had only a small effect on oil recovery.

Dyer[9,10] performed most of his experiments in a linear sand-packed model at 5.5, 2.5 and 1.0 MPa to examine the effect of operating pressure on the process efficiency. The effects of varying slug size and flow velocity were investigated as well. It was found that increased recovery with pressure was due to higher carbon dioxide-oil solubility and increased mobility control as the viscosity of carbon dioxide increased with pressure, and that the 4:1 WAG ratio at a high velocity recovered the most oil.

Prosper[11,12] carried out his experiments in both models: linear and two-dimensional, at 2.5 and 1.0 MPa. The effect of a solution methane gas was investigated. It was observed that the presence of a solution gas increased the recovery.

Table 3.4

Summary of All Immiscible Carbon Dioxide Experiments

Gonzalo Rojas (1982 - 1985)

Comments			Model Parameters					Experimental Parameters				Results		
Run No.	Model Type LC/TD	Process Description	Average Porosity {Ø} (%)	Abs Perm. {k} (darcies)	Oil Visc. {µ} (mPa.s)	Water Sat. {Swc} (%)	Oil Sat. {Soi} (%)	Run Press {p} (MPa)	Ave Flow Vel. (m/d)	CO2 Vol. Inj. (HCPV)	CO2 Moles Inj. (g-mol)	CO2 Required (sm3/sm3)	CO2 Retained (%Inj.)	Total Recovery (%HCPV)
1aR	TD	0.15 HCPV Waterflood (Tertiary)	43.70	10.13	4681	6.4	93.6	5.50	3.41	0.00	0.00	0.0	0.00	1.7
1bR	TD	1 CO2 Slug => 0.33 RHCPV WF & 0.38 m/d CO2	43.70	10.13	4681	7.9	92.1	5.50	3.41	0.04	0.27	38.0	32.41	9.1/9.3
3aR	TD	2.36 HCPV Waterflood (Tertiary)	44.90	10.15	1032	18.5	81.5	5.50	2.27	0.31	2.08	0.0	0.00	45.3
3bR	TD	1 CO2 Slug => 1.42 RHCPV WF & 2.22 m/d CO2	44.90	10.15	1032	55.4	44.6	5.50	2.27	0.31	2.08	40.5	62.93	25.3/46.2
4aR	TD	3.10 HCPV Waterflood & Tank Sand (Tertiary)	43.00	10.60	1032	26.4	73.6	5.50	2.31	0.00	0.00	0.0	0.00	54.4
4bR	TD	1 CO2 Slug => 1.52 RHCPV WF & 2.31 m/d CO2	43.00	10.60	1032	66.5	33.5	5.50	2.31	0.35	2.08	48.9	32.74	13.2/29.1
5R	TD	1 CO2 Slug => 2.18 RHCPV WF & Tank Sand	44.00	7.40	1032	11.7	88.3	5.50	2.27	0.19	1.40	32.9	36.96	55.0
6R	TD	1 CO2 Slug => 2.32 RHCPV WF	43.14	24.25	1032	11.4	88.6	5.50	0.18	0.20	1.42	47.3	54.19	39.2
7R	TD	1 CO2 Slug => 0.66 RHCPV WF	43.70	15.40	1032	9.9	90.1	5.50	0.20	0.21	1.47	70.3	84.03	26.4
8R	TD	1 CO2 Slug => 1.90 RHCPV WF	45.50	15.41	1032	9.0	91	5.50	2.90	0.20	1.53	48.4	25.22	38.3
9R	TD	1 CO2 Slug => 2.06 RHCPV WF & 1.66 m/d CO2	45.67	16.75	1032	9.0	91.1	5.50	1.05	0.20	1.54	55.3	64.76	33.5
10R	TD	1 CO2 Slug => 2.13 RHCPV WF & 0.72 m/d CO2	47.00	17.90	1032	12.3	87.7	5.50	2.32	0.20	1.52	40.4	19.95	45.9
11R	TD	1.72 HCPV Waterflood	38.74	8.70	1032	11.7	88.3	5.50	0.87	0.00	0.00	0.0	0.00	32.4
12R	TD	1 CO2 Slug => 1.84 RHCPV WF & Tank Sand	48.05	4.90	1032	8.1	91.9	5.50	2.90	0.20	1.62	36.3	76.63	50.9
13R	TD	1:1 WAG (5CO2 Slugs)	43.52	11.90	1032	12.4	87.6	5.50	1.15	0.16	1.13	38.6	68.85	38.6
14R	TD	1:1 WAG (10CO2 Slugs)	41.19	10.91	1032	11.7	88.3	5.50	1.16	0.20	1.35	47.3	48.99	39.4
15R	TD	3:1 WAG (10CO2 Slugs)	43.22	11.72	1032	11.1	88.9	5.50	1.16	0.20	1.42	43.7	74.39	42.3
16R	TD	4:1 WAG (10CO2 Slugs)	44.40	14.91	1032	11.3	88.7	5.50	1.44	0.20	1.46	39.0	67.54	47.5
17R	TD	5:1 WAG (10CO2 Slugs)	42.78	12.42	1032	12.7	87.6	5.50	1.16	0.20	1.40	40.5	53.53	46.4
18R	TD	6:1 WAG (10CO2 Slugs)	43.71	14.11	1032	12.2	87.8	5.50	1.47	0.20	1.43	43.3	61.34	43.3
19aR	TD	1.71 HCPV Waterflood (Tertiary)	44.70	14.80	1032	14.3	85.7	5.50	1.43	0.00	0.00	0.0	0.00	35.2
19bR	TD	4:1 WAG (10CO2 Slugs)	44.70	14.80	1032	44.5	55.6	5.50	1.43	0.20	1.42	38.1	63.73	13.5/20.9
20aR	TD	1.63 HCPV Waterflood (Tertiary)	44.91	14.81	1032	10.1	89.9	5.50	1.44	0.00	0.00	0.0	0.00	35.5
20bR	TD	1:1 WAG (10CO2 Slugs)	44.91	14.81	1032	42.0	58	5.50	1.44	0.20	1.54	39.9	64.87	12.5/19.3

Table 3.4

Summary of All Immiscible Carbon Dioxide Experiments (Con't)

Comments			Model Parameters					Experimental Parameters				Results		
Run No.	Model Type LC/TD	Process Description	Average Porosity {Ø} (%)	Abs Perm. {k} (darcies)	Oil Visc. {μ} (mPa.s)	Water Sat. {Swc} (%)	Oil Sat. {Soi} (%)	Run Press {p} (MPa)	Ave Flow Vel. (m/d)	CO2 Vol. Inj. (HCPV)	CO2 Moles Inj. (g-mol)	CO2 Required (sm3/sm3)	CO2 Retained (%Inj.)	Total Recovery (%HCPV)
21aR	TD	1.66 HCPV Waterflood (Tertiary)	43.15	9.26	1032	11.9	88.1	5.50	0.88	0.00	0.00	0.0	0.00	33.8
21bR	TD	6:1 WAG (10CO2 Slugs)	43.15	9.26	1032	41.6	58.4	5.50	0.88	0.20	1.41	40.1	50.36	12.6/19.0
22aR	TD	0.85 HCPV Waterflood (Tertiary)	41.99	9.66	4681	11.0	89	5.50	0.87	0.00	0.00	0.0	0.00	17.1
22bR	TD	4:1 WAG (10CO2 Slugs)	41.99	9.66	4681	26.2	73.8	5.50	0.87	0.20	1.40	68.2	45.38	10.6/12.8
23R	TD	4:1 WAG (10CO2 Slugs)	42.14	9.34	4681	10.9	89.1	5.50	0.87	0.20	1.39	83.6	75.21	22.2
24R	TD	1 CO2 Slug => 1.38 RHCPV WF	44.06	11.51	4681	10.9	89.1	5.50	1.16	0.20	1.45	81.6	31.42	22.8
25R	TD	4:1 WAG (10 CO2 Slugs) & Tank Sand	43.21	4.51	1032	12.2	87.8	5.50	0.44	0.20	1.40	42.2	94.73	43.9

Tao Zhu (1984-1986)

2aZ	TD	1.70 HCPV Waterflood (Tertiary)	37.55	8.50	1032	10.3	89.7	5.50	0.78	0.00	0.00	0.0	0.00	32.5
2bZ	TD	1 CO2 Slug => 2.44 RHCPV WF	37.55	8.50	1032	39.4	60.6	5.50	0.78	0.20	1.27	47.9	35.70	10.8/16.0
3aZ	TD	1.77 HCPV Waterflood (Tertiary)	39.81	9.96	1032	10.2	89.8	5.50	0.78	0.00	0.00	0.0	0.00	29.6
3bZ	TD	4:1 WAG (10 CO2 Slugs)	39.81	9.96	1032	36.8	63.2	5.50	0.78	0.20	1.36	51.6	37.41	6.8/9.6
4Z	TD	4:1 WAG (10 N2 Slugs)	46.51	11.18	1032	18.5	81.5	5.50	1.04	0.20	0.81	33.9	61.74	33.0
5Z	TD	4:1 WAG (10 N2 Slugs)	40.40	11.99	1116	7.0	93	5.50	1.04	0.20	0.80	34.3	22.97	32.5
6Z	TD	4:1 WAG (18 N2 Slugs)	47.04	15.79	1116	17.2	82.9	5.50	1.29	0.21	0.83	35.3	14.09	31.6
7Z	TD	3:1 WAG (10 N2 Slugs)	41.85	16.81	1116	9.0	91	5.50	1.55	0.20	0.81	34.1	17.93	32.7
8aZ	TD	1.00 HCPV Waterflood (Tertiary)	38.55	9.65	1116	8.4	91.6	5.50	0.78	0.00	0.00	0.0	0.00	25.3
8bZ	TD	4:1 WAG (10 N2 Slugs)	38.55	9.65	1116	31.6	68.4	5.50	0.78	0.20	0.76	63.5	36.97	6.3/8.4
9Z	TD	4:1 WAG (10 CO2 Slugs) & 1.32 HCPV N2 Preflush	42.08	17.58	1116	7.9	92.1	5.50	1.55	0.20	1.65	48.2	51.51	43.7
10Z	TD	4:1 WAG (10 CO2 Slugs) & 4.33 HCPV CO2 Preflush	39.87	15.54	1116	7.5	92.5	5.50	1.29	4.53	31.40	758.9	13.28	58.2
11Z	TD	4:1 WAG (10 CO2 Slugs) & 4.27 HCPV CO2 Preflush	40.85	17.40	1116	8.9	91.1	5.50	0.32	4.47	31.25	710.1	0.00	61.2
12Z	TD	1 CO2 Slug => 2.48 RHCPV WF	40.48	12.38	1116	7.6	92.4	5.50	2.07	0.20	1.43	60.3	23.76	33.0
13Z	TD	4:1 WAG (10 CO2 Slugs)	38.71	5.27	1116	9.7	90.3	5.50	2.59	0.20	1.33	54.9	37.05	35.9

Table 3.4

Summary of All Immiscible Carbon Dioxide Experiments (Con't)

Tao Zhu (1984-1986)

Comments			Model Parameters					Experimental Parameters				Results		
Run No.	Model Type LC/TD	Process Description	Average Porosity {Ø} (%)	Abs Perm. {k} (darcies)	Oil Visc. {μ} (mPa.s)	Water Sat. {Swc} (%)	Oil Sat. {Soi} (%)	Run Press {p} (MPa)	Ave Flow Vel. (m/d)	CO2 Vol. Inj. (HCPV)	CO2 Moles Inj. (g-mol)	CO2 Required (sm3/sm3)	CO2 Retained (%Inj.)	Total Recovery (%HCPV)
14Z	TD	4:1 WAG (10 CO2 Slugs)	43.15	16.21	1116	10.1	89.9	5.50	1.55	0.40	2.94	89.2	30.22	43.7
15Z	TD	0.1 HCPV CO2 => 0.1 HCPV N2 => 1.79 HCPV WF	41.12	14.90	1116	9.4	90.6	5.50	1.55	0.10	0.70	27.5	36.78	35.4
16Z	TD	4:1 WAG (10 CO2 Slugs)	39.26	14.28	1116	9.5	90.5	5.50	1.55	0.20	1.34	45.1	45.82	43.0
17Z	TD	4:1 WAG (9 CO2 Slugs)	42.31	18.36	1116	10.1	89.9	5.50	1.55	0.10	0.73	27.9	74.11	35.4
18Z	TD	4:1 WAG (10 CO2 Slugs) & High Perm Streak	38.80	18.10	2107	11.5	88.5	5.50	1.55	0.20	1.29	64.4	45.78	30.3
19Z	TD	4:1 WAG (10 CO2 Slugs) & Parallel Beds	37.24	18.59	2107	7.5	92.5	5.50	1.55	0.20	1.30	85.2	50.13	22.8
20Z	TD	4:1 WAG (10 CO2 Slugs) & Parallel Beds	37.37	16.39	1101	11.3	88.8	5.50	1.55	0.20	1.25	63.9	58.99	30.3
21Z	TD	4:1 WAG (10 CO2 Slugs) & High Perm Streak	38.69	15.84	1101	10.3	89.7	5.50	1.55	0.20	1.31	67.7	51.95	28.8
22Z	TD	4:1 WAG (9 CO2 Slugs)	40.27	13.31	1101	7.1	92.9	2.50	1.29	0.10	0.66	36.9	62.65	25.7
23Z	TD	4:1 WAG (10 CO2 Slugs)	41.16	17.36	1101	9.6	90.4	2.50	1.55	0.20	1.26	55.8	46.22	34.9
24Z	TD	4:1 WAG (10 CO2 Slugs)	41.39	15.40	1233	8.9	91.1	5.50	1.55	0.20	1.42	68.5	98.17	28.2
25Z	TD	4:1 WAG (10 CO2 Slugs)	40.81	8.18	1092	10.1	89.9	5.50	0.78	0.20	1.38	72.1	84.93	26.8
26aZ	TD	0.62 HCPV Waterflood (Tertiary)	40.40	11.22	1092	10.0	90	5.50	1.03	0.00	0.00	0.0	0.00	15.6
26bZ	TD	4:1 WAG (10 CO2 Slugs)	40.40	11.22	1092	24.1	75.9	5.50	1.03	0.20	1.37	68.5	90.34	18.6/22.0
27aZ	TD	1.20 HCPV Waterflood (Tertiary)	42.11	17.74	1092	10.3	89.7	5.50	1.55	0.00	0.00	0.0	0.00	21.8
27bZ	TD	4:1 WAG (10 CO2 Slugs)	42.11	17.74	1092	29.9	70.1	5.50	1.55	0.20	1.31	72.1	96.52	13.9/17.8
28Z	TD	4:1 WAG (10 CO2 Slugs) & Sgi = 13.20% N2	39.03	11.65	1092	10.3	76.5	5.50	1.29	0.23	1.29	64.0	67.66	33.1
29Z	TD	4:1 WAG (7 CO2 Slugs) & Sgi = 11.29% N2	42.72	16.67	1092	12.4	75.7	5.50	1.55	0.21	1.27	91.8	67.17	21.1
30Z	TD	4:1 WAG (10 CO2 Slugs) & Sgi = 15.86% N2	40.53	16.61	1092	9.8	74.6	2.50	1.55	0.20	1.27	67.3	69.69	31.6
31Z	TD	4:1 WAG (10 CO2 Slugs) & Sgi = 14.62% N2	41.08	13.32	1092	11.0	74.3	2.50	1.29	0.20	1.28	95.9	78.54	32.0
32Z	TD	4:1 WAG (10 CO2 Slugs) & Sgi = 3.97% N2 (PB)	35.86	10.18	1092	8.5	87.5	2.50	1.03	0.20	1.26	61.5	87.53	32.2
33Z	TD	4:1 WAG (10 CO2 Slugs) & Sgi = 15.29% N2 (HS)	37.59	18.94	1092	10.6	74.1	2.50	2.59	0.20	1.28	66.7	50.32	33.1

Table 3.4

Summary of All Immiscible Carbon Dioxide Experiments (Cont'd)

Steve Dyer (1986 - 1989)

Comments			Model Parameters					Experimental Parameters				Results		
Run No.	Model Type LC/TD	Process Description	Average Porosity (Ø) (%)	Abs Perm. (k) (darcies)	Oil Visc. (μ) (mPa.s)	Water Sat. (Swc) (%)	Oil Sat. (Soi) (%)	Run Press (p) (MPa)	Ave Flow Vel. (m/d)	CO2 Vol. Inj. (HCPV)	CO2 Moles Inj. (g-mol)	CO2 Required (sm3/sm3)	CO2 Retained (%Inj.)	Total Recovery (%HCPV)
1D	LC	1.92 HCPV Waterflood	35.00	11.10	1059	7.0	93	1.00	0.98	0.00	0.00	0.0	0.00	39.1
2D	LC	1.44 HCPV Waterflood	35.00	5.58	1059	10.0	90	1.00	0.25	0.00	0.00	0.0	0.00	37.6
3D	LC	4:1 WAG (10 CO2 Slugs)	36.60	10.66	1055	12.7	87.3	1.00	0.98	1.79	0.77	30.5	13.80	61.0
4D	LC	4:1 WAG (10 CO2 Slugs)	36.30	11.54	1055	10.8	89.3	1.00	0.98	0.89	0.39	17.4	10.30	55.5
5D	LC	4:1 WAG (5 CO2 Slugs)	35.63	10.81	1055	9.9	90.1	1.00	0.98	0.89	0.39	17.1	2.90	53.9
6D	LC	4:1 WAG (1 CO2 Slugs)	34.10	12.72	1055	10.8	89.2	1.00	0.98	0.89	0.39	24.9	6.00	46.4
7D	LC	4:1 WAG (10 CO2 Slugs)	34.80	15.77	1055	9.4	90.6	1.00	0.98	0.20	0.09	4.4	8.40	47.0
8aD	LC	2.11 HCPV Waterflood (Tertiary)	37.05	11.38	1055	10.3	89.7	1.00	0.98	0.00	0.00	0.0	0.00	38.8
8bD	LC	4:1 WAG (10 CO2 Slugs)	37.05	11.38	1055	45.1	54.9	1.00	0.98	0.20	0.05	2.8	55.60	7.2/11.8
9D	LC	4:1 WAG (10 CO2 Slugs)	36.73	12.67	1055	10.0	90	1.00	0.98	0.10	0.04	2.3	6.00	44.6
10D	LC	4:1 WAG (10 CO2 Slugs)	35.77	10.98	1055	11.1	88.9	1.00	0.98	0.40	0.17	8.6	9.20	49.8
11D	LC	8:1 WAG (10 CO2 Slugs)	38.28	14.00	1055	10.1	90	1.00	0.98	0.20	0.09	4.6	8.00	45.6
12D	LC	2:1 WAG (10 CO2 Slugs)	38.40	16.15	1055	9.2	90.8	1.00	0.98	0.20	0.09	5.2	15.60	40.9
13D	LC	4:1 WAG (10 CO2 Slugs) v/2	36.22	12.12	1055	9.5	90.5	1.00	0.49	0.20	0.09	4.6	53.31	44.9
14D	LC	8:1 WAG (10 CO2 Slugs) v/2	36.93	12.05	1055	9.8	90.2	1.00	0.49	0.20	0.09	4.7	57.78	44.9
15D	LC	2:1 WAG (10 CO2 Slugs) v/2	36.57	12.06	1055	9.7	90.3	1.00	0.49	0.20	0.09	4.7	23.51	44.0
16D	LC	4:1 WAG (10 CO2 Slugs)	34.80	9.02	1059	20.9	79.1	2.50	0.98	0.64	0.75	29.7	93.91	52.7
17D	LC	4:1 WAG (10 CO2 Slugs)	37.70	12.30	1055	10.8	89.2	2.50	0.98	0.20	0.26	12.6	20.46	48.0
18D	LC	4:1 WAG (10 CO2 Slugs)	33.30	5.91	1059	10.3	89.7	5.50	0.98	0.21	0.74	43.4	100.00	46.8
19D	LC	4:1 WAG (10 CO2 Slugs)	34.40	12.36	1059	10.8	89.2	5.50	0.98	0.20	0.70	44.8	98.90	42.9
20D	LC	4:1 WAG (10 CO2 Slugs)	35.77	12.45	1055	10.7	89.3	5.50	0.98	0.20	0.78	37.8	80.04	49.1
21D	LC	4:1 WAG (10 CO2 Slugs)	36.69	15.09	1055	6.1	94	5.50	0.98	0.10	0.42	18.9	68.21	49.0
22D	LC	4:1 WAG (10 CO2 Slugs), Wainwright	36.67	11.41	150	11.8	88.2	1.00	0.98	0.20	0.09	3.4	6.07	65.0

Table 3.4

Summary of All Immiscible Carbon Dioxide Experiments (Cont'd)

Steve Dyer (1986 - 1989)

Comments			Model Parameters					Experimental Parameters				Results		
Run No.	Model Type LC/TD	Process Description	Average Porosity {Ø} (%)	Abs Perm. {k} (darcies)	Oil Visc. {μ} (mPa.s)	Water Sat. {Swc} (%)	Oil Sat. {Soi} (%)	Run Press {p} (MPa)	Ave Flow Vel. (m/d)	CO2 Vol. Inj. (HCPV)	CO2 Moles Inj. (g-mol)	CO2 Required (sm3/sm3)	CO2 Retained (%Inj.)	Total Recovery (%HCPV)
23aD	LC	2.29 HCPV Waterflood, Wainwright (Tertiary)	36.22	11.46	150	13.0	87.1	1.00	0.98	0.00	0.00	0.0	0.00	60.7
23bD	LC	4:1 WAG (10 CO2 Slugs), Wainwright	36.22	11.46	150	65.8	34.2	1.00	0.98	0.20	0.05	1.2	12.52	5.0/12.4
24D	TD	4:1 WAG (10 CO2 Slugs), Senlac	43.10	7.62	3295	13.2	86.8	2.50	0.78	0.61	1.41	45.4	48.91	40.9
25D	TD	4:1 WAG (10 CO2 Slugs), Senlac	41.50	7.41	32.95	9.9	90.1	4.10	0.78	0.33	1.41	40.2	28.68	46.3
26D	TD	4:1 WAG (10 CO2 Slugs), Aberfeldy	40.59	13.31	1055	8.7	91.3	1.00	0.83	0.20	0.16	4.8	65.99	43.3

Gerald Prosper (1988-1991)

1P	TD	4:1 WAG (10 CO2 Slugs)	41.60	13.60	1230	14.1	85.9	2.50	1.29	0.02	0.42	19.7	95.40	32.8
2P	TD	4:1 WAG (10 CO2 Slugs)	41.60	13.90	1115	8.7	91.3	2.50	1.55	0.20	0.45	16.3	35.50	33.9
3P	TD	4:1 WAG (10 CO2 Slugs)	41.10	18.70	1115	8.7	91.3	2.50	2.60	0.10	0.45	7.3	99.10	42.5
4P	TD	4:1 WAG (10 CO2 Slugs)	41.60	13.60	1130	6.8	93.2	2.50	2.60	0.30	0.68	22.5	75.30	40.6
5P	TD	4:1 WAG (10 CO2 Slugs)	43.20	11.50	1135	14.4	85.6	1.00	2.60	0.10	0.08	4.5	99.90	35.8
6P	TD	4:1 WAG (10 CO2 Slugs)	42.10	12.40	1175	15.1	84.9	1.00	2.60	0.20	0.15	4.0	54.00	51.3
7P	TD	4:1 WAG (10 CO2 Slugs)	38.00	11.90	1279	8.9	91.1	1.00	2.60	0.30	0.22	7.2	4.00	43.6
8P	TD	4:1 WAG (10 CO2 Slugs)	38.00	12.20	1046	11.1	88.9	1.00	1.29	0.10	0.07	3.0	15.00	36.8
9P	TD	4:1 WAG (10 CO2 Slugs)	38.00	11.80	1046	4.2	95.8	1.00	1.29	0.20	0.15	4.1	38.00	46.4
10P	TD	4:1 WAG (10 CO2 Slugs)	39.50	12.10	1046	8.3	91.7	1.00	1.29	0.30	0.23	6.1	12.30	44.1
11P	LC	4:1 WAG (10 CO2 Slugs)	37.60	11.40	1055	9.8	90.2	2.50	0.98	0.89	1.13	47.6	16.80	50.2
12P	LC	4:1 WAG (10 CO2 Slugs)	36.40	11.00	1055	20.6	79.4	2.50	0.98	0.20	0.22	9.5	14.30	57.0
13P	LC	4:1 WAG (10 CO2 Slugs)	37.60	14.10	1055	6.3	93.7	2.50	0.98	0.40	0.53	27.7	25.00	41.1
14P	LC	4:1 WAG (10 CO2 Slugs)	37.40	13.10	1230	5.1	94.9	2.50	0.98	0.20	0.22	11.1	12.40	51.1
15aP	LC	2.02 HCPV Waterflood (Tertiary)	36.50	9.90	882	7.5	92.5	2.50	0.98	0.00	0.00	0.0	0.00	41.5
15bP	LC	4:1 WAG (10 CO2 Slugs)	36.50	9.90	882	45.8	54.2	2.50	0.98	0.20	0.24	5.5	36.90	20.2/34.6

Table 3.4

Summary of All Immiscible Carbon Dioxide Experiments (Cont'd)

Gerald Prosper (1988-1991)

Comments			Model Parameters					Experimental Parameters				Results		
Run No.	Model Type LC/TD	Process Description	Average Porosity {Ø} (%)	Abs Perm. {k} (darcies)	Oil Visc. {µ} (mPa.s)	Water Sat. {Swc} (%)	Oil Sat. {Soi} (%)	Run Press {p} (MPa)	Ave Flow Vel. (m/d)	CO2 Vol. Inj. (HCPV)	CO2 Moles Inj. (g-mol)	CO2 Required (sm3/sm3)	CO2 Retained (%Inj.)	Total Recovery (%HCPV)
16P	LC	4:1 WAG (10 CO2 Slugs)	37.10	11.20	1130	8.2	91.8	2.50	0.98	0.05	0.06	3.3	99.40	46.4
17P	LC	4:1 WAG (10 CO2 Slugs), Live Oil	36.70	9.20	784	11.3	88.7	1.00	0.98	0.20	0.08	3.4	****	64.8
18P	LC	4:1 WAG (10 CO2 Slugs), Live Oil	39.90	11.80	784	9.5	90.5	1.00	0.98	0.40	0.20	6.6	****	64.8
19P	LC	4:1 WAG (10 CO2 Slugs), Live Oil	36.70	13.60	784	5.0	95	1.00	0.98	0.10	0.05	2.0	****	62.5
20P	LC	4:1 WAG (10 CO2 Slugs), Live Oil	35.70	10.20	784	5.9	94.1	1.00	0.98	0.20	0.09	4.3	****	63.5
21P	LC	4:1 WAG (10 CO2 Slugs), Live Oil	38.90	14.20	784	7.7	92.3	1.00	0.98	0.20	0.09	3.8	****	65.0
22aP	LC	2.26 HCPV Waterflood, Live Oil (Tertiary)	35.10	10.50	784	8.0	92	1.00	0.98	0.00	0.00	0.0	0.00	55.3
22bP	LC	4:1 WAG (10 CO2 Slugs), Live Oil	35.10	10.50	784	58.9	41.1	1.00	0.98	0.20	0.04	1.4	****	12.3/27.6

Abbreviations and Symbols

Tank Sand = Cleaned Aberfeldy Tank Sand
Continuous CO2 => WF = A sinlge CO2 Slug Slug Followed by a Waterflood
High Perm. Streak (HS) = Diagonal Bed of High Permeability Glass Beads
Parallel Beds (PB) = Layer of Sand and a Layer of Glass Beads

"R" = Gonzalo Rojas
"Z" = Tao Zhu
"D" = Steve Dyer
"P" = Gerald Prosper
"LC" = Linear Model
"TD" = Two-Dimensional Model

WF = Waterflood
CO2 = Carbon Dioxide Gas
N2 = Nitrogen Gas
Sgi = Initial N2 Gas Saturation

CO2 Required = Total CO2 Injected (Std. Cond.)/Total Oil Produced
CO2 Retained = Percentage of Total CO2 Injected Not Produced
Total Recovery = Process Recovery + Waterflood Recovery + Blowdown Recovery

3.8 Simulation of The Immiscible Carbon Dioxide Process

Reid and Robinson[85] modelled the Lick Creek Meakin project using a three-phase, three-dimensional compressible reservoir simulator. The results indicated that alternate carbon dioxide/water injection with cyclic carbon dioxide stimulation of the producing wells was the preferred process to produce oil from the Meakin sand and that recycling of the produced carbon dioxide reduced the carbon dioxide requirement. Their results also indicated that the injected carbon dioxide flowed preferentially through the upper part of the reservoir, while the injected water flowed through the lower part. As a result, the highest oil saturation occurred in the upper part of the reservoir, which was swept by carbon dioxide, but not by water. According to the results, cyclic carbon dioxide stimulation of the producers improved oil rates, reduced water-oil ratios, increased carbon dioxide coverage of the reservoir, dispersed carbon dioxide rapidly throughout the reservoir, and caused the wells to flow.

Klins and Farouq Ali[73] developed a two-dimensional and three-phase (oil, water, and carbon dioxide) simulator to investigate the efficiency of gaseous carbon dioxide as a recovery agent for moderately viscous oils. The simulator assumed zero diffusional mixing, non-volatile oil, and thermodynamic equilibrium between phases. The results demonstrated that over the viscosity range of 1 to 1000 mPa.s, carbon dioxide flooding was superior to nitrogen injection, natural depletion, or waterflooding for oil viscosities above 70 mPa.s. Their results also indicated that for a 1000 mPa.s oil, less than 1% recovery was obtained by natural depletion, 16% by waterflooding, and 25% by carbon dioxide flooding. Ultimate recovery was sensitive to critical gas saturation. For a 1000 mPa.s oil, recovery increased 8% as critical gas saturation was increased from 0 to 10%. Oil recovery by carbon dioxide injection was found to be strongly dependent on initial oil saturation as well. For a 1000 mPa.s oil, recovery increased from 3 to 25 to 29%, as the oil saturation was increased from 40 to 60 to 70%, respectively.

Spivak and Chima[30] designed an equation of state compositional simulator to investigate the mechanisms of immiscible injection of 18 mole% nitrogen-82 mole% carbon dioxide mixture in heavy oil reservoir in Wilmington field. Their simulator did not account for the effect of dispersive forces and carbon dioxide-induced viscous forces on oil recovery. Their simulation results showed that it took a longer time for a 18 mole% nitrogen-82 mole% carbon dioxide mixture to dissolve in oil than for pure carbon dioxide and that for 18 mole% nitrogen-82 mole% carbon dioxide mixture gas breakthrough was earlier, the compositional fronts were more dispersed, and the recovery was 3% lower compared to pure carbon dioxide. They explained that the difference in recoveries was due to the difference in carbon dioxide solubilities and the corresponding difference in oil viscosities, and concluded that the immiscible carbon dioxide drive process in heavy oil reservoirs can be looked at as a process of viscosity reduction, followed by waterflooding of the reduced viscosity oil.

Bakshi, Ogbe, Kamath, and Hatzignatiou[86] used a commercial, three-phase, adaptive implicit, black oil simulator to evaluate the performance of a carbon dioxide stimulation process in the West Sak field. Their simulation results indicated that the soak period had only a small effect on oil recovery with the shorter soak periods yielding marginally higher oil recoveries. The effect of slug size was also determined. It was found that the slug size became less important for larger slugs. They explained that since the carbon dioxide solubility in oil levelled off at higher pressures, it caused a decrease in incremental oil swelling and viscosity reduction. As a result, the additional oil recovery due to carbon dioxide solubility became less important at larger slug sizes.

3.9 Immiscible Carbon Dioxide Projects

In this section, selected immiscible carbon dioxide floods, as well as carbon dioxide huff 'n' puff projects, will be briefly reviewed.

3.9.1 Immiscible Carbon Dioxide WAG Flood Projects

Bati Raman Project

Bati Raman field[87], located in Southeast Turkey, holds the largest oil reserve in the nation. The total estimated oil reserve was 300×10^6 sm^3 of 10-12°API and 450.0 to 1,000.0 mPa.s crude oil at the reservoir pressure and temperature of 12.4 MPa and 71°C, respectively.

Initially the field was planned for huff 'n' puff application using carbon dioxide gas from a natural carbon dioxide field in Dodan, about 80 kms from Bati Raman. The gas contains mainly 91.0% carbon dioxide, 3.1% nitrogen, 2.6% methane, 3.3% ethane, and quite a small amount of hydrogen sulfide. Due to the lack of confinement of the injected carbon dioxide gas in the project area which resulted in low production, the planned huff and puff was converted to a continuous immiscible carbon dioxide flood. The injection of carbon dioxide was started at a total average rate of 623,000 sm^3/d using eighteen injectors, which was then increased to 1,400,000 sm^3/d in February 1987. Within a few months after the start of the carbon dioxide injection, oil production rate was increased to 159 from 32 sm^3/d and to 273 from 63.6 sm^3/d. With the success of this method, the number of injectors was increased to thirty at the end of 1990. Thus, the average oil production rate was pushed to 1,779 sm^3/d at the end of 1990. After four years of operation, the cumulative total oil recovery, as reported in December 1990, was 1.1×10^6 sm^3. The average volume of carbon dioxide required to produce 1 sm^3 of oil was 3,920 sm^3.

Lick Creek Project

The Lick Creek project[85] is located in Bradley and Union Counties, Arkansas. An immiscible WAG process has been proved to be effective in recovering oil from thin heavy oil sands. The project was anticipated to recover an incremental 10% of the 17°API and 160 mPa.s in-place oil from a high permeability Meakin sandstone reservoir. Injection of 40% HCPV slug of carbon dioxide on a 1:1 WAG ratio was performed in three phases. In the first phase, cyclic carbon dioxide injection into the producers and injectors was carried out to increase the reservoir pressure and to allow wells to be flowed naturally. In the second phase, large volumes of carbon dioxide were injected into the permanent injectors. In the third phase, carbon dioxide and water were alternatively injected into the injectors. After this phase, the unit was waterflooded. After five years of production since 1976, the total oil recovered was 170,000 sm^3, with an average production rate between 95 sm^3/d and 67 sm^3/d. The field was projected to produce an additional 582,000 sm^3 of oil within the next fifteen years.

Hansford Marmaton Project

The Hansford Marmaton field[88], located in Hansford County of the Texas Panhandle, is operated by Stanberry Oil Company. This project has proven that carbon dioxide can be used to repressure a depleted reservoir. After a primary production of 0.26×10^6 sm^3 of oil, reservoir pressure fell to 1.4 MPa. Immiscible injection of 389×10^6 sm^3 of carbon dioxide raised the pressure to near the miscibility pressure, after which the recycled gas was injected at a predetermined WAG ratio. With the existing free gas phase in the reservoir, carbon dioxide was distributed throughout, contacting more of the OOIP than would have been contacted by miscible displacement given the unfavorable carbon dioxide mobility ratio. Due to the immiscible effects of carbon dioxide, oil rates increased to 95.4 sm^3/d from 4.8 sm^3/d. Cumulative oil production after eight years of carbon dioxide injection was $0.18\text{x}10^6$ m^3, which was about 70% of the total oil recovery under primary or about 10% of the OOIP with a net carbon dioxide utilization of $2.2\text{x}10^3$ sm^3/sm^3 of oil. Carbon dioxide utilization was reduced to $1.3\text{x}10^3$ sm^3/sm^3 of oil when the project was completed.

Wilmington Project

The use of immiscible carbon dioxide in a WAG mode to enhance the recovery of 14°API crude oil has been carried out by Long Beach Oil Development Co. in the Wilmington Tar Zone in the Los Angles Basin of California[89]. The project was begun in 1982 with injection of a mixture of about 85 mole% carbon dioxide and 15 mole% nitrogen into the Tar zone of Fault Block V. As of August 1986, about $233\text{x}10^6$ sm^3 of gas was injected. The produced gas was recycled and re-injected. In this project, the presence of nitrogen was a complicating factor. On one hand, nitrogen reduced the solubility of carbon dioxide in the oil approximately according to the law of partial pressures. On the other hand, the presence of nitrogen, which was insoluble in oil, resulted in trapping of free nitrogen by the injected water, which, in turn, could result in a lower residual oil to water. The production response was good. As of the end of August 1987, the incremental recovery was $342\text{x}10^3$ sm^3 with a theoretical carbon dioxide requirement of 603.8 sm^3/sm^3 of oil.

Hilly Upland Project

This pilot test[90] in West Virginia was conducted by the Alleghany and Mineral Company. Field test results showed that low formation permeability (about 3 md) did not preclude the injection of carbon dioxide and that when water cannot be injected at economical rates to repressure a reservoir or to displace the solvent slug in a tight dolomitized limestone reservoir, carbon dioxide could be used instead. This pilot test also demonstrated that the swelling of oil, viscosity reduction, and increase in reservoir energy due to carbon dioxide injection resulted in 5% OOIP incremental recovery, with an estimated carbon dioxide requirement of 1,153 sm^3/sm^3 of oil.

3.9.2 Immiscible Carbon Dioxide Huff 'n' Puff Projects

Texas Gulf Coast Project

Texaco tested the feasibility of an immiscible carbon dioxide huff 'n' puff process on twenty-eight wells in Texas Gulf Coast[91] Miocene Reservoirs. From these tests in twelve unnamed oil fields, viscosity reduction and oil swelling appeared to be the principal mechanisms of recovery since no compositional changes were noticed in the produced oil. These tests were conducted on light oils with gravities ranging from 23° to 30°API and viscosities ranging from 1.6 to 33.4 mPa.s. Increased oil recoveries were slightly improved for the more viscous oils and lower API gravities. Based on incremental recovery, these tests showed that, for these reservoirs, a soak period of 2 to 3 weeks seemed better than shorter or longer time and that injection of 230,000 m^3 of carbon dioxide resulted in greater incremental oil recovery of a 33.4 mPa.s oil.

Timbalier Bay Project

This immiscible huff 'n' puff test conducted in the 1,494 m Reservoir (BA) Sand Unit, Timbalier Bay Field[92], Louisiana by Chevron proved the feasibility of using carbon dioxide to recover a 26°API and 2.8 mPa.s oil at reservoir conditions from the bottomwater-drive sandstone reservoir. The test in two wells showed that when properly administered the carbon dioxide huff 'n' puff process can provide a quick pay out with a low capital investment. The results indicated that incremental oil was recovered through the oil swelling and viscosity reduction effects. The process was to inject 291.7×10^9 m^3 of carbon dioxide in each producer and then shut in for a soak period, after which it was returned to production. These tests measured carbon dioxide stimulation efficiencies of 27.4 to 33.5 km^3/m of pay and carbon dioxide utilizations of 204.8 to 562.8 m^3/m^3. The incremental oil recovery reported for these tests were 518.9 to 1,756.3 m^3.

Appalachian Basin Project

Cyclic carbon dioxide injection tests were performed in about sixty-five production wells located in the Appalachian basin[93] in eastern Kentucky. The field was pressure-depleted and contains a 32°API oil. It was targeted for carbon dioxide huff 'n' puff because of its tight and discontinuous formation and disappointing waterflood results. These tests were conducted in conjunction with a laboratory evaluation at Lousiana State

University which addressed the potential application of immiscible cyclic carbon dioxide injection.

The usual cyclic carbon dioxide test procedure was to first pull rods from the well and inject the carbon dioxide slug down the tubing at a rate of several cubic meters per minute. The well was then shut in without corrosion inhibitors for one week. After the initial soak period, the well was then returned to production. Response to cyclic carbon dioxide injection was a sharp rise in oil production rates which continued for fifteen to forty-eight months after which production returned to the original hyperbolic decline curve. The resulting low carbon dioxide utilizations of about 178 sm^3/m^3 attest to the economic viability of huff 'n' puff in light oil reservoirs.

CHAPTER 4

EXPERIMENTAL APPARATUS and PROCEDURE

This chapter presents a description of the apparatus, materials, and procedures used in the present research. The first part describes the procedure for packing and saturating the model prior to conducting an experiment, and the second part gives details of how the diffusivity and solubility of carbon dioxide in oil, in the presence of nitrogen, were measured. A discussion of the procedure for conducting an immiscible WAG experiment is also provided.

4.1 Experimental Apparatus

Figure 4.1 gives an overview of the apparatus used for the experiments. As shown, the apparatus used in this study consists of the physical model, fluids and porous medium, fluid injection and production systems, and the data acquisition system.

4.1.1 Physical Models

Two models: linear and two-dimensional, were used in the present research. The linear model was partially scaled while the two-dimensional model was fully scaled to the Aberfeldy reservoir in Saskatchewan (Details are given in Section 3.6). The linear model was built to act as a screening model for the two-dimensional model. It was 415 mm in length and 98 mm in diameter. Chevron-type fittings were used to seal the ends of the pipe, as well as forming the injection and production ports.

In contrast to the linear model, the two-dimensional model was more complex. Much effort was expended in designing and fabricating it[5]. A brief description of this model is given below.

- Rectangular shape: 45.7 cm x 45.7 cm x 2.2 cm.
- Three reinforcing members
- Maximum internal pressure: 10.0 MPa.
- Maximum deflections of walls at 10.0 MPa: < 0.01 mm.
- Weight of model: 1.0 tonne.
- Number of wells: 9
- Possible patterns to simulate: 5-spot, 9-spot, line drive.
- The model can be rotated for horizontal, inclined, or vertical floods.

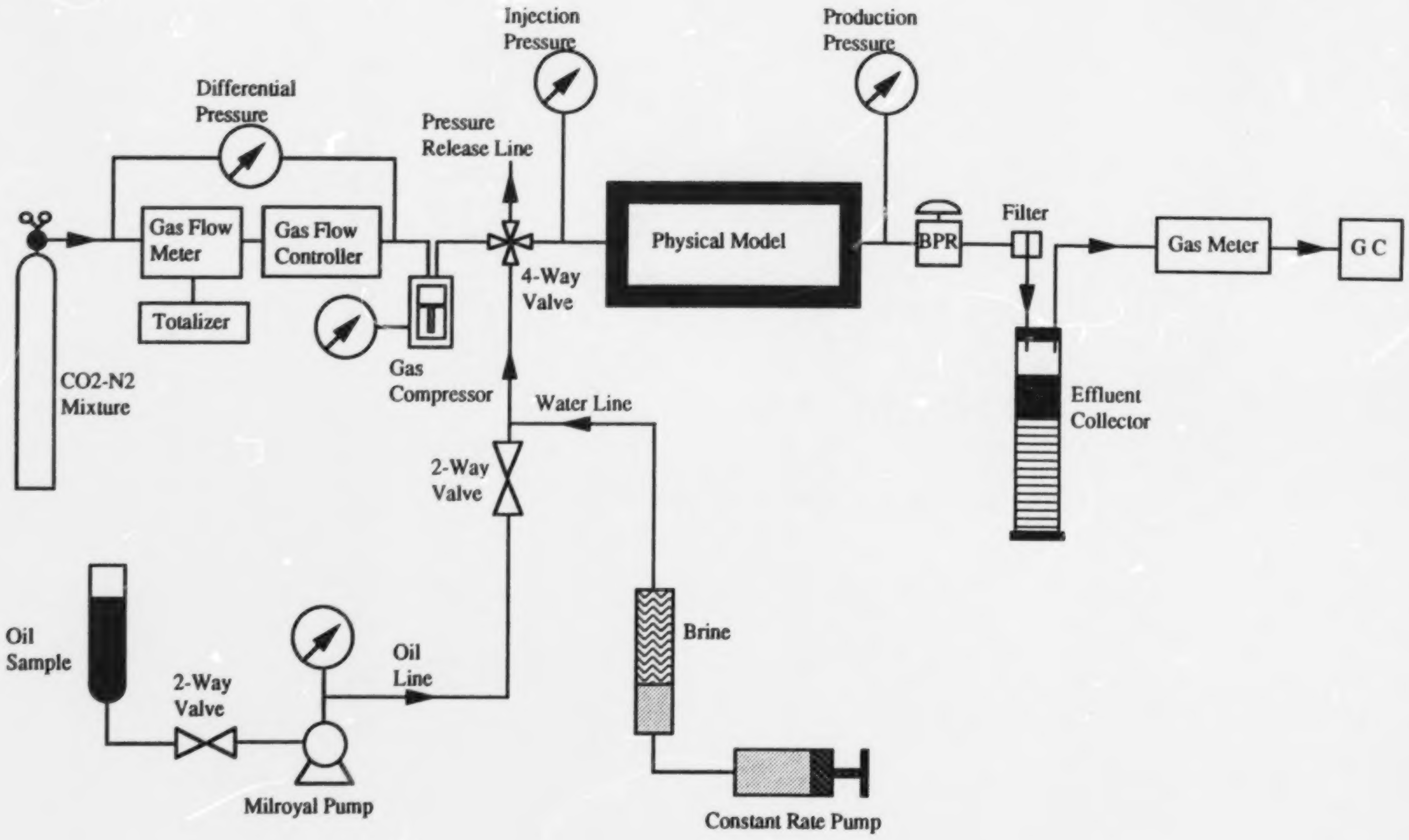

Injection
Pressure
Production
Pressure
Differential
Pressure
Pressure
Release Line
Gas Flow
Meter
Gas Flow
Controller
4-Way
Valve
Physical Model
BPR
Filter
Gas Meter
G C
Totalizer
CO2-N2
Mixture
Gas
Compressor
Water Line
Effluent
Collector
2-Way
Valve
Brine
Oil
Sample
2-Way
Valve
Oil
Line
Milroyal Pump
Constant Rate Pump

Figure 4.1 - Schematic of the Experimental Apparatus.

4.1.2 Fluids and Porous Medium

Oil

The oil used in all experiments was from the Aberfeldy field in Lloydminster, Saskatchewan. Initially, it contained a large volume of reservoir water; therefore, it had to be dehydrated by drying in an oil drier at a constant temperature of 40°C. After about four to five weeks the water content was reduced to less than 0.5% by volume. After dehydration, the viscosity was measured using a Brookfield viscometer. The initial viscosity was approximately 4500 mPa.s. Since this value was too high, it was then reduced to the scaled viscosity of 1058 mPa.s by adding a conventional light oil (Faxam-100), with a viscosity of 270 mPa.s.

Nitrogen-Carbon Dioxide Mixtures

Nitrogen-carbon dioxide mixtures of various compositions were used in all impure carbon dioxide experiments. The nitrogen compositions in the mixtures were 4.98, 9.99, 15.0, 20.0, 25.0, and 30.0 mole%. Due to the unavailability of mixing equipment, these mixtures were purchased from Medigas.

Brine

Aberfeldy simulated brine was used in all runs. It had a refractive index of 1.3446, which is the refractive index of Aberfeldy brine.

Porous Medium

For the model porous medium, Ottawa Silica Sand from Ottawa, Michigan, was used to represent the field porous medium since it has a grain size similar to that of the Aberfeldy reservoir sand (70-140 mesh).

4.1.3 Fluid Injection and Production System

Gas Injection

A nitrogen-carbon dioxide mixture was injected using a Matheson gas metering system. This system controlled and measured the gas entering the model. The Matheson Dyna-Blender helped to control the flow rate of gas. A gas compressor was also used to maintain the constant gas injection pressure. A Matheson totalizer provided the cumulative volume of gas injected into the model.

Oil Injection

A positive displacement Milroyal pump was employed to inject heavy oil into the model. To avoid oil fingering in brine, oil was injected at a flow rate of 7% capacity of the pump (about 300 cm^3/hr), or lower.

Brine Injection

Brine was injected by a constant rate screw-type piston pump. The pump flow rate was controlled by varying the pump speed.

Fluid Production

The effluent was collected in a glass cylinder at atmospheric conditions (101.325 kPa and 23°C). Oil and water, because of their heavier densities than gas, were collected at the bottom of the cylinder while gas displaced a volume of water in the upright glass burette equal to the total volume of gas produced. Since oil and water mixed with each other at the time of collection, they had to be heat-separated to determine the produced volumes of each.

4.1.4 Data Acquisition System

The production pressure was controlled by a back-pressure regulator which was connected to the production end of the model. Two Heise pressure gauges were used to measure the injection and production pressures.

4.2 Experimental Procedures

In this research, as mentioned previously, two models: linear and two-dimensional, were used to conduct experiments. The terms 'Linear' and 'Two-Dimensional' are used for convenience only; in fact, flow in any physical model is three-dimensional. Much effort was made to minimize the effect of gravity, the third dimension.

For both models, the experimental procedures used were identical, except that dry packing was used for the linear model and wet packing for the two-dimensional model. The procedures are as discussed below.

4.2.1 Packing

Linear Model

Dry packing was used for the linear model. The packing procedure is relatively simple. After the bottom Chevron end cap was installed on the production end of the model, the model was inverted so that the open (injection) end was up and that it was perfectly vertical. A level gauge was used to check if it was in the vertical position. An air vibrator was then strapped on the side of the model. Next, Ottawa sand was slowly poured into the model while it was being vibrated. This way, a tight sand pack was achieved. Afterwards, the model was left vibrating for eight-to-ten hours. After vibration, the top Chevron end cap was closed, and a vacuum pump was connected to the top end to evacuate air from the model while it was again being vibrated for another eight-to-ten hours. The model was vacuumed at the top to achieve the best vacuum possible. At this point, the model was ready for pore volume determination.

Two-Dimensional Model

While the linear model was dry-packed, the two-dimensional model was wet-packed for convenience. Similar to the linear model, the two-dimensional model was first inverted so that the open cavity was facing up. Next, an aluminium extension was temporarily mounted on the top of the model, and distilled water was added to the model. The purpose of the extension was to maintain a 10-cm head of water above the sand level. An air vibrator was clamped on the top of the model and activated, and Ottawa sand was slowly poured in until the sand level was about 2 cm above the head of the model. The model was then vibrated for at least eight-to-ten hours. Afterwards, the 10-cm head of water, air vibrator, and casing were removed, and the top flange was put on and bolted. Finally, the model was pressure-tested at about 6.0 MPa to check for leaks. If no leak was detected, the model was now ready for pore volume determination.

4.2.2 Pore Volume Determination

Linear Model

After the model was vacuumed, a plastic tube from a calibrated cylinder containing an initially known volume of brine was connected to the bottom end of the model and brine was drawn up into the model due to the pressure difference between the model and the atmosphere. By injecting water from the bottom of the model, a more accurate pore volume and a more uniform water saturation could be achieved. The difference between the initial and final volumes of brine yielded the pore volume of the model. Whence, the porosity was calculated by dividing the pore volume by the bulk volume of the model.

Two-Dimensional Model

For the two-dimensional model, determination was more time-consuming than that for the linear model. First, the model was rotated so that the flange side faced down. Next, brine with a refractive index of 1.3446 was injected at the bottom of the model using the constant rate screw-type piston pump, while distilled water was being produced and collected at the top of the model. Brine injection was continued until the refractive index of the produced water reached 1.3446. At this time, the model was believed to be 100% brine saturated, and the injection was stopped. For each sample of water collected, its refractive index was measured using a refractometer to estimate a gradual change from water to brine solution. The refractive indices of the first and last water sample were plotted versus the percent of brine in solution since it was believed that the first sample contained 0.0% brine and the last 100.0% brine (Figure 4.2). From this plot, knowing the refractive index of each water sample, the percent of brine in solution could be found. To determine the pore volume of the model, the percent of brine in solution was plotted versus the cumulative volume of water produced, and the area under the curve was divided into two equal portions (Figure 4.3). The pore volume was the cumulative volume at which area A equalled to area B.

4.2.3 Permeability Determination

For both linear and two-dimensional models, the permeability was measured using the same approach. Note that after pore volume determination, the model was brine saturated, thus brine was used as the fluid to measure the permeability of the sand pack. The horizontal permeability of the model was measured by flowing brine through the

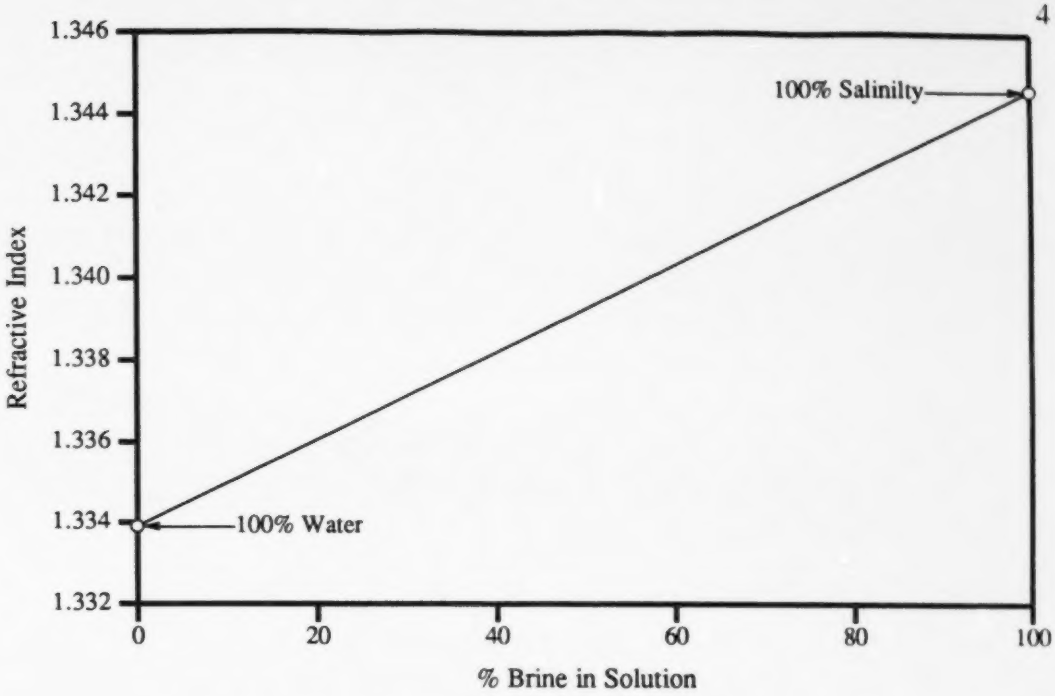


Figure 4.2 - 2-D Model Fraction of Brine in Solution.

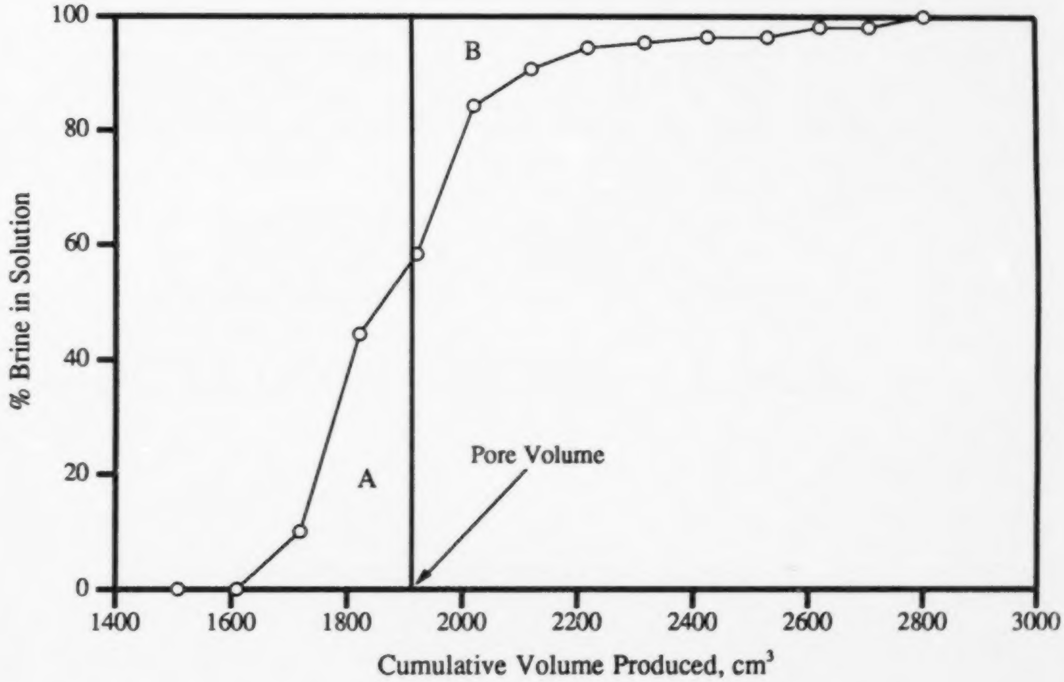


Figure 4.3 - 2-D Model Pore Volume Determination.

model in a horizontal position, at a specific flow rate and pressure differential. A known volume of water was collected at a given time and pressure differential, and the permeability was determined using Darcy's linear flow equation.

4.2.4 Oil Saturation

For both physical models, the procedures to saturate the model sand pack with oil were similar. First, the model was inverted so that the injection port was facing up and the production port facing down, and the model pressure was brought to the experimental pressure by injecting brine into the model with the production back-pressure regulator (BPR) closed. Also, oil had to be pressurized to the experimental pressure by activating the constant rate Milroyal pump, with the inlet valve closed, until the oil pressure was at least a little higher than or equal to the model pressure. Then it was injected into the model at a very slow rate by fully opening the inlet valve. Right after the oil breakthrough occurred, injection was stopped and the volume of brine produced was recorded. This volume of brine was used to predict the initial oil saturation, which is as follows.

$$S_{oi} = \frac{\text{HCPV}}{\text{Pore Volume}}$$

For the linear model:

$$S_{oi} = \frac{\text{Brine Volume Produced - Oil Volume in Chevron - Type Caps}}{\text{Pore Volume}} \times 100\%$$

For the two-dimensional model:

$$S_{oi} = \frac{\text{Brine Volume Produced}}{\text{Pore Volume}} \times 100\%$$

At this time, the model was believed to be oil-saturated and ready for an experiment.

4.2.5 WAG Process, Post Waterflood, and Blowdown

The same procedure was used to conduct an experiment in both physical models. To start an experiment, the volumes of gas and brine to be injected had to be calculated first. The calculation procedure is shown below.

Since it was found by the previous researchers that a total gas slug size of 20% HCPV and a water volume four times the gas volume, both of which were divided into ten equal slugs, were optimal, they were used in all experiments in this study.

Total Gas Volume @ Experimental Conditions = 0.20 × HCPV [cm^3]
It had to be converted to its equivalent volume at the meter (standard) conditions

Total Gas Volume @ Meter Conditions

$$= 0.20 \times \mathrm{HCPV} \times \frac{\mathrm{MD\ @\ Experimental\ Conditions}\left(\mathrm{mol/cm^3}\right)}{\mathrm{MD\ @\ Meter\ Conditions}\left(\mathrm{mol/cm^3}\right)} \quad [\mathrm{cm}^3]$$

Where:

MD = molar density calculated using the Starling Equation of State.

Total Brine Volume = 4 × Total Gas Volume @ Experimental Conditions [cm^3]
Finally, the total gas and brine volumes were divided into ten slugs each.

After the preliminary calculations had been completed, the model was prepared to start an experiment. With the model in the horizontal position, a gas slug was first injected then followed by a water slug until ten slug pairs of gas and water had been injected, and the WAG process ended.

The WAG process was followed by the "post-waterflood". This warterflood was carried out only when, after the WAG process, the producing WOR was still below 20:1. The model was flooded with brine until the WOR reached 20:1, or higher, when the waterflood was terminated. The "blowdown" was commenced by first closing the injection valve and then slowly lowering the pressure to the atmospheric pressure by releasing the production BPR. Subsequently, the model was left for at least eight hours to make sure all gas was produced. At this time, the experiment was terminated.

After the termination of the experiment, the model was opened and the sand pack was removed and discarded. The model, as well as the injection and production ports, were cleaned first with Varsol, then toluene, and readied for the next experiment. The data collected were analyzed to determine various parameters indicative of the overall performance of the experiment. These data are given in Appendix A. A typical run took a total of two weeks.

4.2.6 Data Processing

The experimental data were processed using a previously developed computer program. The program was modified to process nitrogen-carbon dioxide experimental data. This program was based on the material balance of oil, water, and nitrogen-carbon dioxide mixture. The volume of fluids injected was calculated by this program. It also computed the water-oil ratios (WOR), gas-oil ratios (GOR), oil recovery, the total volume of oil produced, oil produced-fluid injected ratio (OPFIR), nitrogen-carbon dioxide retention and nitrogen-carbon dioxide required to produce a unit volume of oil.

The nitrogen-carbon dioxide material balance used the Starling equation of state[94], together with its mixing rules, to calculate the moles of nitrogen-carbon dioxide mixture injected and produced. The equation of state is as follows:

$$p = \rho RT + \left(B_o RT - A_o - \frac{C_o}{T^2} + \frac{D_o}{T^3} - \frac{E_o}{T^4}\right)\rho^2 + \left(bRT - a - \frac{d}{T}\right)\rho^3 + \alpha\left(a + \frac{d}{T}\right)\rho^6$$
$$+ \frac{c\rho^3}{T^2}\left(1 + \gamma\rho^2\right)\exp\left(-\gamma\rho^2\right)$$

Where

p = pressure (MPa)
T = Temperature (K)
ρ = molar density (kmol/m^3)

The constants for carbon dioxide in SI units are:

$A_o = 0.176976$ $B_o = 0.024588$ $C_o = 2.451876E04$
$D_o = 1.883482E06$ $E_o = 2.631556E04$ $R = 0.008314$
$a = 0.009434$ $b = 0.003784$ $c = 1.4197888E03$
$d = 0.055761$ $\alpha = 0.0000961229$ $\gamma = 0.006421$

The constants for nitrogen in SI units are:

$A_o = 0.112428$ $B_o = 0.0422649$ $C_o = 1143.6859$
$D_o = 8.9909E04$ $E_o = 3.11307E06$ $R = 0.008314$
$a = 0.00235560$ $b = 0.00324822$ $c = 43.703149$
$d = 0.0290594$ $\alpha = 0.0000736446$ $\gamma = 0.00428738$

For nitrogen-carbon dioxide mixture, the following mixing rules, as proposed by Starling[94], were used to calculate the molar density of the mixture.

$$A_o = \sum_{i=1}^{n}\sum_{j=1}^{n} x_i x_j A_{oi}^{1/2} A_{oj}^{1/2}\left(1 - k_{ij}\right)$$

$$B_o = \sum_{i=1}^{n} x_i B_{oi}$$

$$C_o = \sum_{i=1}^{n}\sum_{j=1}^{n} x_i x_j C_{oi}^{1/2} C_{oj}^{1/2}\left(1 - k_{ij}\right)$$

$$D_o = \sum_{i=1}^{n}\sum_{j=1}^{n} x_i x_j D_{oi}^{1/2} D_{oj}^{1/2}\left(1 - k_{ij}\right)^4$$

$$E_o = \sum_{i=1}^{n}\sum_{j=1}^{n} x_i x_j E_{oi}^{1/2} E_{oj}^{1/2}\left(1 - k_{ij}\right)^5$$

$$a = \left[\sum_{i=1}^{n} x_i a_i^{1/3}\right]^3 \qquad b = \left[\sum_{i=1}^{n} x_i b_i^{1/3}\right]^3 \qquad c = \left[\sum_{i=1}^{n} x_i c_i^{1/3}\right]^3$$

$$d = \left[\sum_{i=1}^{n} x_i d_i^{1/3}\right]^3 \qquad \alpha = \left[\sum_{i=1}^{n} x_i \alpha_i^{1/3}\right]^3 \qquad \gamma = \left[\sum_{i=1}^{n} x_i \gamma_i^{1/2}\right]^2$$

Newton's method was applied to the above equation, together with its mixing rules, to determine the molar densities of nitrogen-carbon dioxide mixtures of various compositions. According to Starling[94], the above equation predicts experimental density data with an average error of less than 1.0%.

4.3 Diffusivity and Solubility Experiments

4.3.1 Diffusivity of Carbon Dioxide into Oil

4.3.1.1 Diffusion Cell

The diffusion cell used in this study is shown in Figure 4.4. It was made up of a stainless steel cylinder fitted with two flanges. The internal cross-sectional area of the cell was 32.17 cm^2 and the length was 122.0 cm. The cell was always placed in the vertical position during the packing and cleaning, as well as the actual experiments. The top flange was connected to a high pressure nitrogen-carbon dioxide mixture cylinder. A Heise pressure gauge was also connected to the top flange to measure the pressure inside the cell during the experiment. The bottom flange was equipped with a two-way high pressure valve which permitted the collection of oil samples for determining the concentration of diffused nitrogen-carbon dioxide in oil at the end of the experiment.

4.3.1.2 Diffusivity Experiments

The procedure for conducting a diffusion experiment was as follows. First, the diffusion cell was evacuated for six hours using a vacuum pump connected to the top flange of the cell. Next, while the cell was still being evacuated, a plastic tube from a calibrated cylinder containing an initially known volume of oil was connected to the bottom valve, and oil was drawn up into the cell to obtain an oil column of at least 20 cm, and the bottom valve was closed. A nitrogen-carbon dioxide mixture at 1.0 MPag was injected into the cell at the top flange, and the pressure was kept constant during the course of the experiment. After about twenty days, three samples - one at the bottom, one in the middle, and one at the top of the oil column - were taken, and the volumes of gas liberated were measured. The experiment was terminated. The cell was opened and cleaned to prepare for the next experiment.

4.3.2 Solubility of Carbon Dioxide in Oil

Figure 4.5 presents the schematic of the mixing apparatus. It consisted of a Milroyal pump, a mixing chamber, and a gas meter. The procedure to determine the solubility of carbon dioxide in oil was relatively simple. The mixing chamber was first evacuated for two hours, then it was filled with approximately 1000 ml of oil. Afterwards, the top two-way valve was connected to a high pressure carbon dioxide cylinder, and oil was mixed with carbon dioxide at 1.0 MPa for approximately three days using a Milroyal pump. After three days, a sample of oil was withdrawn from the bottom of the chamber and the volume of gas liberated from oil was trapped and measured.

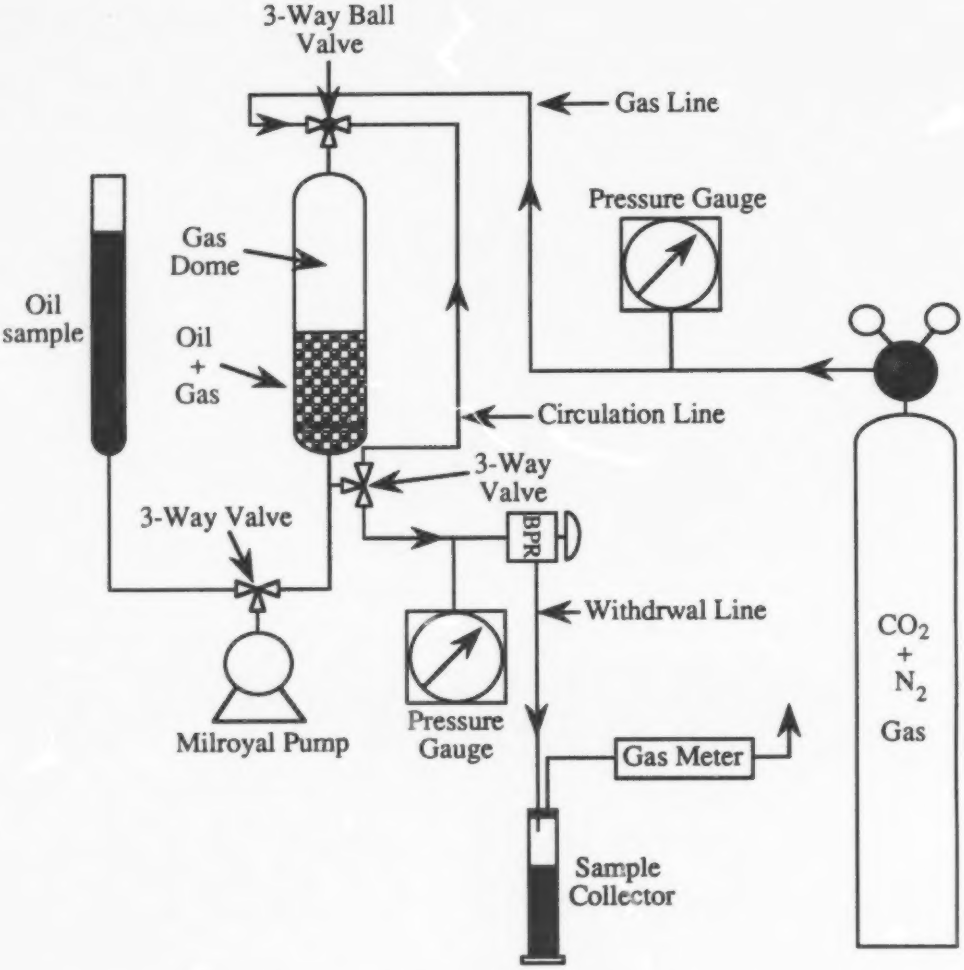

3-Way Ball Valve
Gas Line
Pressure Gauge
Gas Dome
Oil sample
Oil + Gas
Circulation Line
3-Way Valve
3-Way Valve
BPR
Withdrwal Line
CO_2 + N_2 Gas
Milroyal Pump
Pressure Gauge
Gas Meter
Sample Collector

Figure 4.5 - Schematic of the Mixing Apparatus.

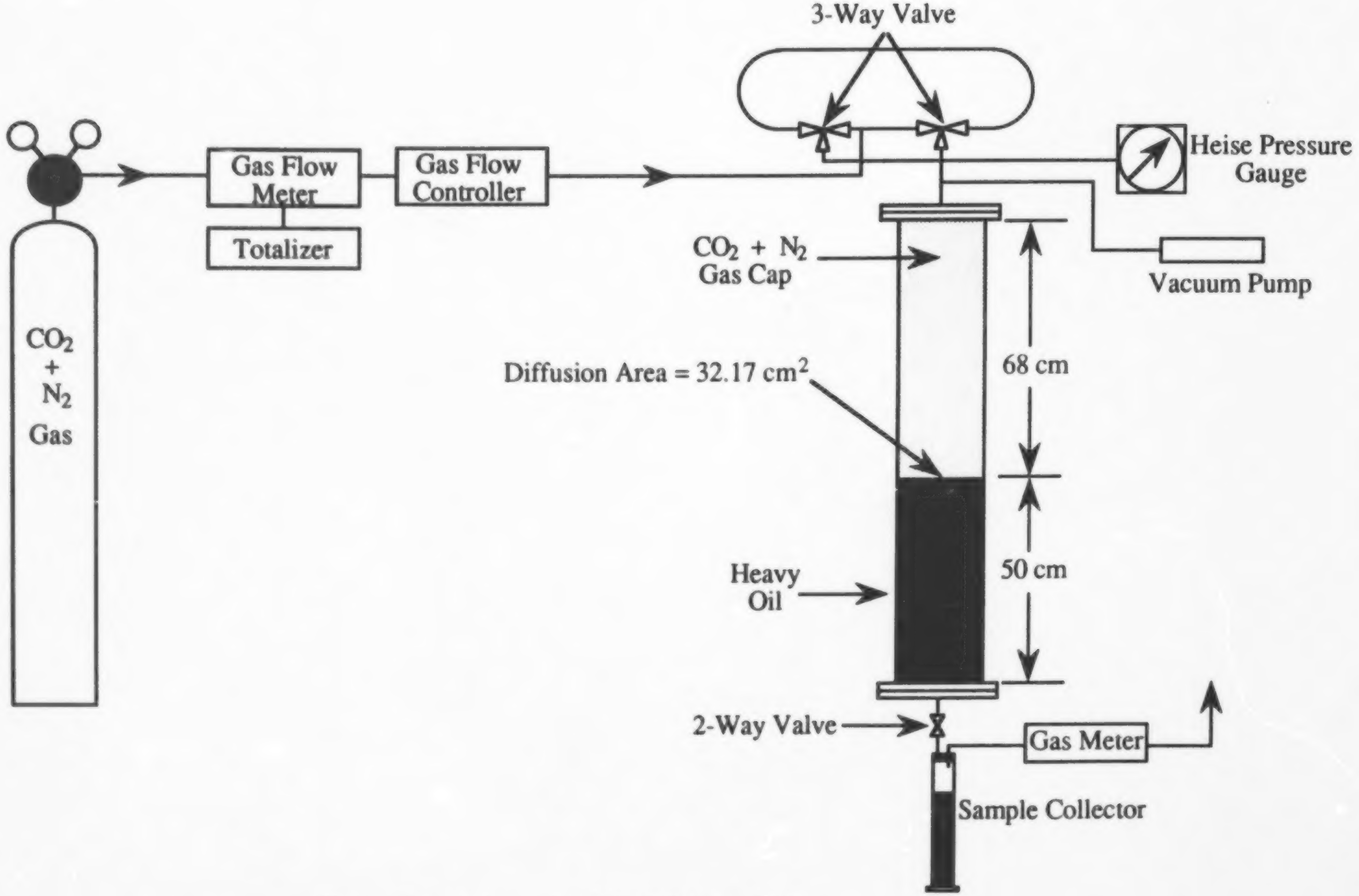

3-Way Valve
CO$_2$ + N$_2$ Gas
Gas Flow Meter
Totalizer
Gas Flow Controller
Heise Pressure Gauge
Vacuum Pump
CO$_2$ + N$_2$ Gas Cap
Diffusion Area = 32.17 cm^2
68 cm
50 cm
Heavy Oil
2-Way Valve
Gas Meter
Sample Collector

Figure 4.4 - Schematic of the Diffusion Cell.

CHAPTER 5

PRESENTATION AND DISCUSSION OF RESULTS

This chapter consists of two parts. The first part deals with the presentation and discussion of the experimental work done to investigate the solubility and diffusivity of carbon dioxide and nitrogen-carbon dioxide mixtures into a crude oil. The second part discusses the experimental results obtained using the two physical models: linear and two-dimensional.

5.1 Solubility of Pure Carbon Dioxide and Nitrogen-Carbon Dioxide Mixtures in Aberfeldy Heavy Oil

The solubility of carbon dioxide in a crude oil is defined as the volume of carbon dioxide in sm^3 per sm^3 of the carbon dioxide saturated dead oil at the specified pressure and temperature. In this research, the solubilities of pure carbon dioxide and nitrogen-carbon dioxide mixtures, with nitrogen concentrations of 9.99, 20.0, and 30.0 mole% were measured at 1.0 MPa and 23°C, the conditions at which most of the experiments were conducted.

Figure 5.1 presents a plot of the measured solubilities of pure carbon dioxide and nitrogen-carbon dioxide mixtures vs. the mole fraction of nitrogen. As is shown, the presence of nitrogen in carbon dioxide had a tendency to reduce the solubility of carbon dioxide in oil. The carbon dioxide solubility dropped from 12.5 sm^3/sm^3 (for pure carbon dioxide) to about 7.45 sm^3/sm^3 (for a 30 mole% nitrogen-70 mole% carbon dioxide mixture). This reduction is about 40.0% of the pure carbon dioxide solubility. Also, it is interesting to note that the solubility of carbon dioxide in Aberfeldy heavy oil decreased linearly as its nitrogen content increased. In other words, the solubility of carbon dioxide in a mixture is about one-half of what the carbon dioxide concentration in the mixture would imply.

Based on the data presented by Svrcek and Mehrotra[25], nitrogen is much less soluble in a heavy crude oil than carbon dioxide. Moreover, since it is classified as a "non-condensible" gas, its solubility in a heavy crude oil is negligible at low pressures. Therefore, when it is mixed with carbon dioxide, it causes a decrease in the carbon dioxide solubility in oil. The main reason that is believed to contribute to the reduction of carbon dioxide solubility in oil is the decrease in the carbon dioxide partial pressure due to

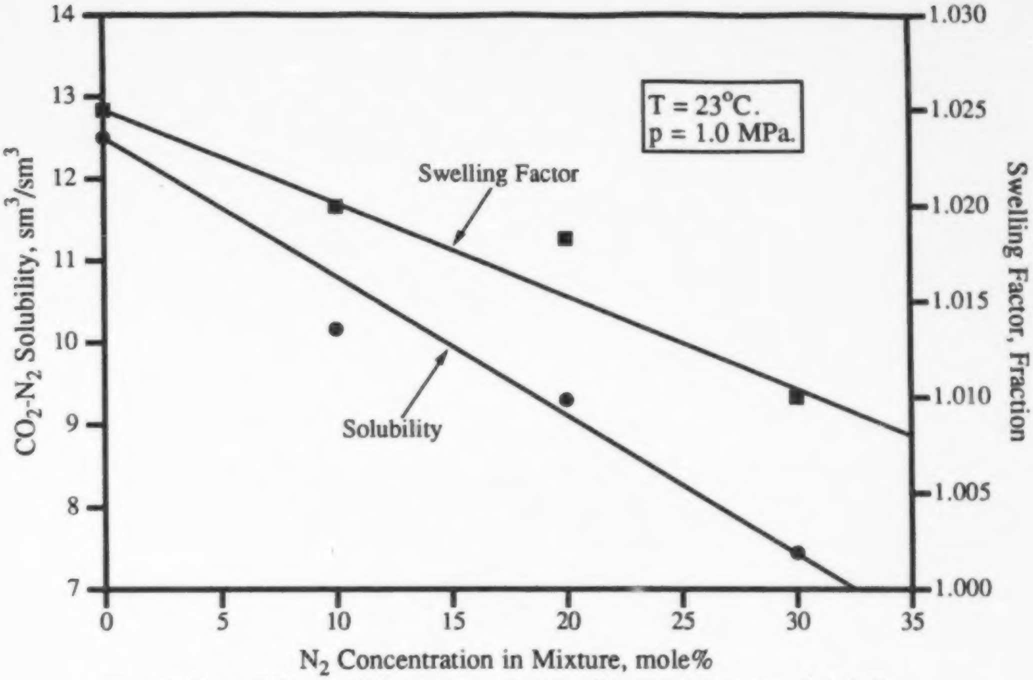


Figure 5.1 - Effect of Nitrogen on Carbon Dioxide-Nitrogen Solubility and Oil Swelling.

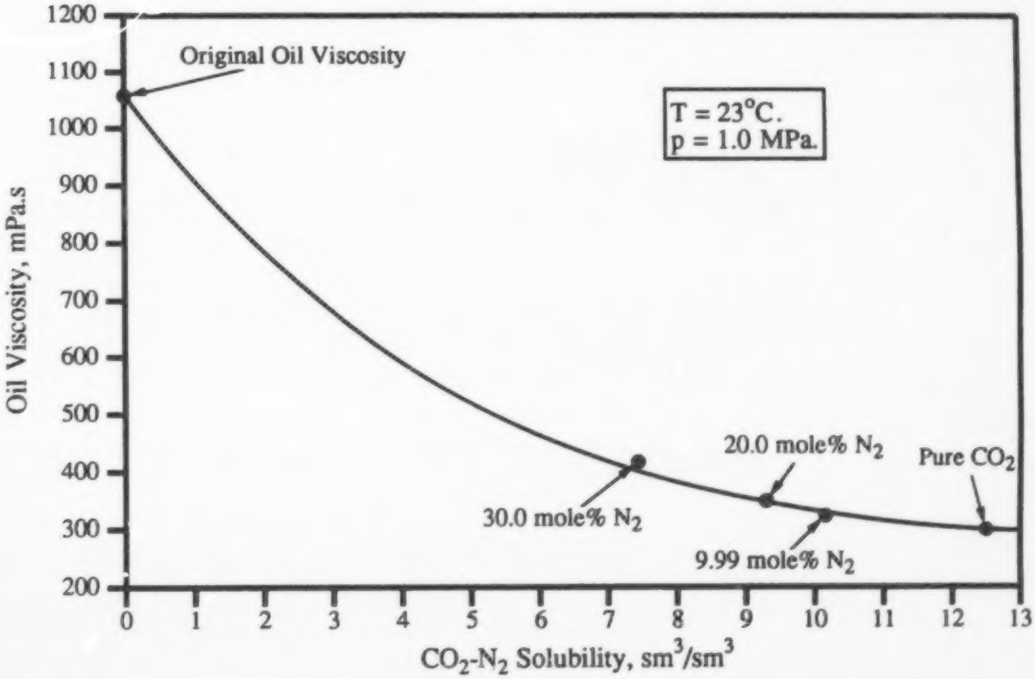


Figure 5.2 - Effect of Carbon Dioxide-Nitrogen Solubility on Oil Viscosity.

the presence of nitrogen. Thus, the higher the nitrogen content in a nitrogen-carbon dioxide mixture, the lower is the carbon dioxide partial pressure; as a result, the solubility of carbon dioxide will be lowered as the nitrogen partial pressure increases, as was observed in this investigation.

5.1.1 Effect of Solubility on Oil Swelling

The increase in the volume or "swelling" of the oil is directly related to the solubility of carbon dioxide in oil and increases as the solubility increases. The swelling factor, which is defined as the volume of the oil with dissolved carbon dioxide at the specified pressure and temperature divided by the volume of oil without carbon dioxide at standard conditions[32], is used to measure the swelling of the oil due to the solubility of carbon dioxide in oil. The swelling factor plot in Figure 5.1 shows a decrease in oil swelling as a result of a decrease in carbon dioxide solubility in oil due to the presence of nitrogen. The swelling factor for each gas-oil mixture was estimated using Simon and Graue's correlation[32]. As shown, the shape of the swelling factor line is similar to that of the solubility line. The swelling factor decreased as the solubility of carbon dioxide decreased or the nitrogen content in carbon dioxide increased.

5.1.2 Effect of Solubility on Oil Viscosity

The presence of nitrogen with carbon dioxide led to an increase in the viscosity of the carbon dioxide-oil mixture. Figure 5.2 provides the resulting effect of the decreased carbon dioxide solubility on the oil viscosity. The viscosity values were calculated using the correlation proposed by Singh, Mutyala, and Puttagunta[95]. The viscosity of the oil, when it was saturated with pure carbon dioxide, was estimated to be approximately 300.0 mPa.s, whereas it was about 400.0 mPa.s when it was saturated with a 30 mole% nitrogen-70 mole% carbon dioxide mixture. This increase was about 33% of the 300.0 mPa.s value. The curve in Figure 5.2 shows an increase in the viscosity of the carbon dioxide-oil mixture when there was a decrease in the carbon dioxide solubility or an increase in the nitrogen content.

5.2 Diffusivity of Pure Carbon Dioxide and Nitrogen-Carbon Dioxide Mixtures into Aberfeldy Heavy Oil

Three experiments were carried out to determine the molecular diffusion of pure carbon dioxide and nitrogen-carbon dioxide mixtures into Aberfeldy heavy oil at 1.0 MPa and 23°C, under static conditions (Experiments DE-1, DE-2, DE-3). Experiment DE-1 was performed with pure carbon dioxide, while experiments DE-2 and DE-3 utilized a 15.0 mole% nitrogen- 85 mole% carbon dioxide mixture and a 30.0 mole% nitrogen-70 mole% carbon dioxide mixture, respectively. The diffusion apparatus as sketched in Figure 4.4 (Chapter 4) was employed to conduct all three experiments.

After the gas space of carbon dioxide (or nitrogen-carbon dioxide mixture) was left in contact with a 50-cm column of oil (without any mechanical agitation) for at least 20 days, three small oil samples - one at the bottom, one in the middle, and one at the top of the oil column - were taken. In experiments DE-2 and DE-3, a 25-cm column of oil was used instead to reduce the long experiment time which would be needed in the case of a mixture of nitrogen and carbon dioxide. As recommended by Denoyelle and Bardon[47], a minimum oil column of 20 cm should be used in any carbon dioxide diffusion experiment at reservoir pressure and under static conditions to minimize the effect of any convection. Also, the diffusion of carbon dioxide into oil, or the concentration of carbon dioxide decreases with increasing distance from the carbon dioxide-oil contact. This is why three small oil samples at three different places were taken. A better result could have been achieved if many small samples were taken; but this is time-consuming since for each sample taken, at least one day must be allowed for the diffused carbon dioxide to be completely released from the oil.

Tables 5-1 to 5-3 present the data and results obtained for the three experiments. The molecular diffusion coefficient of carbon dioxide into oil was estimated using Fick's law of diffusion which has the following finite difference form:

$$D_o = -\frac{1}{A\frac{\Delta C}{\Delta L}}\frac{\Delta G}{\Delta t}$$

To apply this law to calculate the molecular diffusion coefficient, the following assumptions were made:

1. The effect of convection induced by density changes was ignored[5].
2. The concentration gradient in the oil column was assumed to be linear[5].
3. For nitrogen-carbon dioxide experiments, the volume of gas released from oil was assumed to be carbon dioxide only, i.e., nitrogen volume was very small and thus neglected.

TABLE 5-1

Data and Results of Experiment DE-1 (Pure CO_2)

Constant Values

Diffusional Pressure = 1.0 MPa

Diffusional Temperature = 23°C

Oil Molecular Weight = 424 g/mole

Oil Density = 0.9324 g/cm^3

CO_2 Molecular Weight = 44.01 g/mole

CO_2 Density = 0.01908 g/cm^3

Oil Column = 52.0 m

Diffusion Time = 1740600 s (483.50 hrs)

Internal Cross Sectional Area of the Diffusion Cell = 32.17 cm^2

	Bottom Sample	Middle Sample	Top Sample
Weight of Oil Collected, g	80.44	82.11	65.94
Mole of Oil, moles	0.1897	0.1937	0.1555
Mole of CO_2, moles	0.02286	0.02381	0.02472
Concentration of CO_2 in oil, mole/mole	0.1205	0.1230	0.1589
Molar Fraction of Oil, %	0.8925	0.8905	0.8629
Molar Fraction of CO_2, %	0.1075	0.1095	0.1371
Concentration Gradient of CO_2, mole/cm^3-cm	-7.5167E-06	-7.5127E-06	-7.4613E-06
Molar Flux of CO_2, mole/s	1.4201E-08	1.3679E-08	1.3133E-08
Molecular Diffusion Coefficient, cm^2/s	5.4312E-05	5.6599E-05	5.9162E-05

Therefore, the average diffusion coefficient of CO_2 in oil was 5.6691E-05 cm^2/s (5.6691E-09 m^2/s).

N.B: The negative sign denotes that the carbon dioxide (CO_2) concentration decreases with distance.

TABLE 5-2

Data and Results of Experiment DE-2 (15 mole% N_2-85 mole% CO_2)

Constant Values

Diffusional Pressure = 1.0 MPa

Diffusional Temperature = 23°C

Oil Molecular Weight = 424 g/mole

Oil Density = 0.9324 g/cm^3

CO_2 Molecular Weight = 41.61 g/mole

N_2-CO_2 Density = 0.01782 g/cm^3

Oil Column = 24.6 cm

Diffusion Time = 1794000 s (498.33 hrs)

Internal Cross Sectional Area of the Diffusion Cell = 32.17 cm^2

	Bottom Sample	Middle Sample	Top Sample
Weight of Oil Collected, g	75.82	99.38	102.48
Mole of Oil, moles	0.1788	0.2344	0.2417
Mole of CO_2, moles	0.00323	0.01973	0.03508
Concentration of CO_2 in oil, mole/mole	0.0181	0.0842	0.1451
Molar Fraction of Oil, %	0.9822	0.9244	0.8733
Molar Fraction of CO_2, %	0.0178	0.0776	0.1267
Concentration Gradient of CO_2, mole/cm^3-cm	-1.6562E-05	-1.5909E-05	-1.5702E-05
Molar Flux of CO_2, mole/s	1.9553E-08	1.0999E-08	1.8024E-09
Molecular Diffusion Coefficient, cm^2/s	3.3829E-06	2.1491E-05	3.8709E-05

Therefore, the average diffusion coefficient of CO_2 in oil was 2.1194E-05 cm^2/s (2.1194 E-09 m^2/s).

N.B: The negative sign denotes that the carbon dioxide (CO_2) concentration decreases with distance.

TABLE 5-3

Data and Results of Experiment DE-3 (30 mole% N_2-70 mole% CO_2)

Constant Values

Diffusional Pressure = 1.0 MPa

Diffusional Temperature = 23°C

Oil Molecular Weight = 424 g/mole

Oil Density = 0.9324 g/cm^3

N_2-CO_2 Molecular Weight = 39.21 g/mole

CO_2 Density = 0.01661 g/cm^3

Oil Column = 26.0 cm

Diffusion Time = 1814400 s (504hrs)

Internal Cross Sectional Area of the Diffusion Cell = 32.17 cm^2

	Bottom Sample	Middle Sample	Top Sample
Weight of Oil Collected, g	75.82	64.35	77.54
Mole of Oil, moles	0.1788	0.1518	0.1829
Mole of CO_2, moles	0.00122	0.00369	0.00625
Concentration of CO_2 in Oil, mole/mole	0.0068	0.0243	0.0342
Molar Fraction of Oil, %	0.9932	0.9763	0.9670
Molar Fraction of CO_2, %	0.0068	0.0237	0.0330
Concentration Gradient of CO_2, mole/cm^3-cm	-1.5875E-06	-1.5406E-05	-1.5274E-05
Molar Flux of CO_2, mole/s	6.7154E-10	2.0337E-09	3.4419E-09
Molecular Diffusion Coefficient, cm^2/s	1.3149E-06	4.1035E-06	7.0049E-06

Therefore, the average diffusion coefficient of CO_2 in oil was 4.1411E-06 cm^2/s (4.1411E-10 m^2/s).

N.B: The negative sign denotes that the carbon dioxide (CO_2) concentration decreases with distance.

Several observations can be made about the diffusivity of pure carbon dioxide and nitrogen-carbon dioxide mixtures into oil under static conditions. First, the molecular diffusion coefficients calculated from the three samples taken at the end of each experiment show that the diffusivity of pure carbon dioxide and nitrogen-carbon dioxide mixtures decreased with increasing distance from the gas-oil contact. It is thus obvious that in an immiscible WAG experiment, the viscosity of oil nearer to the injection end will be lower than that nearer to the production end. Second, pure carbon dioxide had a larger diffusion rate than a nitrogen-carbon dioxide mixture, since the molecular diffusion coefficients of the three samples taken in experiment DE-1 were respectively higher than those taken in experiments DE-2 and DE-3. Third, the diffusivity of carbon dioxide into oil drastically decreased with an increase in nitrogen concentration. As shown, the average molecular diffusion coefficient decreased about three fold and about fourteen fold when the concentrations of nitrogen in carbon dioxide were 15.0 and 30.0 mole%, respectively.

Comparing the average molecular diffusion coefficient of pure carbon dioxide obtained in this study with that obtained at 5.5 MPa in a previous study[5,19] reveals that the value obtained in this study is nearly twice as high. The reasons are that a diffusion time of 483.5 hrs was allowed in this study, while only 166 hrs were allowed in the previous study; and that during the course of the experiment, while gas was diffusing into oil, the gas phase pressure was maintained constant by injecting gas into the cell whenever it dropped below 1.0 MPa, whereas it was not kept constant in the previous study. Also, the technique of taking oil samples at the end of the experiment is believed to have contributed to a lower diffusion coefficient value in the previous study. Oil samples were taken in an open system; thus, a large unknown volume of carbon dioxide liberated from the carbon dioxide-oil mixture was not trapped and lost to atmosphere. As a result, the calculated diffusion coefficient was lower. In this study, all carbon dioxide released was trapped and measured. That is why a higher value was obtained in this measurement.

A comparison of the values obtained in this work with those reported by Denoyelle and Bardon[47] shows that the former are lower because of the much higher pressure and temperature (15 MPa and 80°C) used in the previous study.

Based on the results obtained in this study, the presence of nitrogen in carbon dioxide drastically decreases the diffusion rate of carbon dioxide into oil. As a result, the oil viscosity will be lowered less than in the case of pure carbon dioxide.

5.2.1 Effect of Nitrogen on the Carbon Dioxide-Oil Interfacial Tension

Based on the results presented in Section 5.2, the presence of nitrogen also led to an increase in carbon dioxide-oil interfacial tension. From the molar mass values of pure carbon dioxide, nitrogen-carbon dioxide mixtures, and oil presented in Tables 5-1 to 5-3, the interfacial tension can be evaluated using the Macleod-Sugden correlation[96,97] which is expressed as follows:

$$\sigma = \left[\sum_j P_j \left\{ x_j \frac{\rho_o}{MW_o} - y_j \frac{\rho_g}{MW_g} \right\}_j \right]^4$$

where

σ = interfacial tension, dynes/cm
P = parachor
ρ_o = density of oil, g/cm^3
ρ_g = density of carbon dioxide or nitrogen-carbon dioxide mixture, g/mole
MW_o = molecular weight of oil, g/mole
MW_g = molecular weight of carbon dioxide or nitrogen-carbon dioxide mixture, g/mole

For pure carbon dioxide, the interfacial tension was found to be 14.73 dynes/cm (14.73 mN/m) while it was 21.76 dynes/cm (21.76 mN/m) for a 15 mole% nitrogen-85 mole% carbon dioxide mixture and 22.75 dynes/cm (22.75 mN/m) for a 30 mole% nitrogen-70 mole% carbon dioxide mixture. These values demonstrate that the presence of nitrogen increased the carbon dioxide-oil interfacial tension, which is believed to have an adverse effect on oil recovery.

5.3 DISPLACEMENT RESULTS

The second part of this chapter presents a discussion of the pure carbon dioxide experiments done in previous studies[9,11] and of nitrogen-carbon dioxide experiments done in the present study. For the present study, a total of forty-six experiments were conducted to determine the sensitivity of oil recovery to the presence of nitrogen with carbon dioxide instead of pure carbon dioxide in the immiscible WAG process. Thirty-four experiments were successfully completed, while the other twelve were partially successful due to mechanical problems such as gasket, BPR, or pump leakage. Tables 5.4a and 5.4b, respectively, summarize the thirty-two and fourteen experiments carried out in the linear and two-dimensional models. The prefixes "1" and "2" in run No. refer to linear and two-dimensional models, respectively. The unreliable values in the tables (for the incomplete runs) are indicated by a question mark. A typical run took a total of two weeks, depending on the type of run.

Figure 5.3 provides an outline of the different experiments conducted in the linear and two-dimensional models. The linear model experiments are divided into two groups. The first group consists of the experiments conducted using a 1058 mPa.s oil and nitrogen-carbon dioxide mixtures containing 4.98, 9.99, 15.0, 20.0, 25.0, and 30.0 mole% nitrogen at 1.0 MPa and 23°C. The second group contains the experiments conducted using a 888 mPa.s oil. The second group is made up of two sub-groups. The first sub-group contains the experiments conducted utilizing the same experimental conditions and parameters and gas mixtures used in the first group of experiments. The second sub-group contains the experiments conducted to investigate the effects of varying slug size and carbon dioxide/nitrogen partial pressure and volume. As for the two-dimensional model experiments, they are repeats of the selected linear model experiments, to observe the character of multi-dimensional displacement.

For each run conducted, the data collected were plotted for analysis. Three different types of plots were prepared for each run. The first plot is a volumetric balance to check for experimental errors. The second plot is a production history showing producing WOR, producing GOR, cumulative oil recovery, and instantaneous oil produced-fluid injected ratio (OPFIR), all versus cumulative pore volume of fluid injected. This plot also shows when the gas breakthrough occurred. The third plot shows the oil recovery distribution for each slug injected during various injection stages.

Table 5.4a

Summary of CO2-N2 WAG Experiments in a Linear Model

Run No.	WAG Ratio	No. of Slugs	Average Porosity {Ø} (%)	Average Perm. {k} (darcies)	Oil Vis. {μ} (mPa.s)	Oil Sat. {Soi} (%)	Expt. Press. {p} (MPa)	CO2 Press. {pco2} (MPa)	CO2-N2 Volume Injected (%HCPV)	%N2 in Mix.	CO2 Volume Injected (%HCPV)	Ave. Flow Vel. (m/d)	CO2-N2 Retention (%Inj.)	CO2-N2 Requirement (sm3/sm3)	Average WAG Production Rate (cc/sec) Oil	Average WAG Production Rate (cc/sec) Gas	Average WAG Production Rate (cc/sec) Water	Recovery (%HCPV) WAG	Recovery (%HCPV) PWF	Recovery (%HCPV) BD	Recovery (%HCPV) Total	Run No.
1DT1	4:1	10	35.73	11.31	1058.0	94.98	1.00	0.95	20.00	4.98	19.00	0.984	39.71	4.39	0.026	0.092	0.036	36.2	11.6	1.3	49.8	1DT1
1DT2	4:1	10	35.82	10.70	1058.0	94.86	1.00	0.90	20.00	9.99	18.00	0.984	34.42	4.56	0.024	0.092	0.036	33.8	14.1	0.8	48.7	1DT2
1DT3	4:1	10	36.06	10.51	1058.0	92.44	1.00	0.85	20.00	15.00	17.00	0.984	21.91	4.78	0.024	0.099	0.035	33.7	11.5	2.4	47.6	1DT3
1DT4	4:1	10	35.59	10.77	1058.0	95.53	1.00	0.80	20.00	20.00	16.00	0.984	14.72	5.05	0.023	0.144	0.033	33.6	9.3	2.4	45.3	1DT4
1DT5	4:1	10	35.16	10.63	1058.0	95.28	1.00	0.75	20.00	25.00	15.00	0.984	10.13	5.13	0.023	0.144	0.035	33.3	9.2	2.5	45.0	1DT5
1DT6	4:1	10	35.70	10.73	1058.0	95.54	1.00	0.70	20.00	30.00	14.00	0.984	9.73	5.36	0.022	0.150	0.035	31.5	10.9	1.9	44.3	1DT6
1DT7	4:1	10	35.83	11.04	888.0	94.98	1.00	1.00	20.00	0.00	20.00	0.984	43.65	4.02	0.027	0.089	0.031	38.1	16.1	1.3	57.9	1DT7
1DT8	4:1	10	36.43	11.18	888.0	94.99	1.00	0.95	20.00	4.98	19.00	0.984	43.41	4.18	0.026	0.091	0.033	36.8	15.9	2.8	55.5	1DT8
1DT9	4:1	10	36.06	11.14	888.0	94.71	1.00	0.90	20.00	9.99	18.00	0.984	40.60	4.32	0.026	0.101	0.048	36.2	12.9	5.5	54.6	1DT9
1DT10	4:1	10	35.73	11.53	888.0	95.05	1.00	0.85	20.00	15.00	17.00	0.984	20.63	4.30	0.025	0.106	0.030	40.2	10.1	4.3	54.5	1DT10
1DT11	4:1	10	35.77	11.89	888.0	94.12	1.00	0.80	20.00	20.00	16.00	0.984	8.87	4.31	0.024	0.126	0.032	38.9	12.2	3.2	54.3	1DT11
1DT12	4:1	10	35.77	11.43	888.0	95.77	1.00	0.75	20.00	25.00	15.00	0.984	3.06	4.45	0.024	0.126	0.032	37.5	13.6	1.4	52.5	1DT12
1DT13	4:1	10	35.22	11.09	888.0	96.16	1.00	0.70	20.00	30.00	14.00	0.984	1.36	4.72	0.024	0.126	0.034	33.9	15.5	2.0	51.4	1DT13
1DT14	4:1	10	35.90	11.69	888.0	95.51	1.20	1.00	20.00	15.00	17.00	0.984	53.67	5.56	0.027	0.088	0.058	38.6	21.1	1.5	61.0	1DT14
1DT15	4:1	10	35.43	10.78	888.0	95.46	1.35	1.00	20.00	25.00	15.00	0.984	51.17	5.46	0.027	0.095	0.061	37.9	14.7	4.3	56.9	1DT15
1DT16	4:1	10	35.51	10.02	888.0	95.12	1.44	1.01	20.00	30.00	14.00	0.984	32.96	5.93	0.027	0.107	0.033	37.5	14.0	4.3	56.5	1DT16
1DT17	4:1	10	35.61	10.24	888.0	95.59	1.00	0.85	23.53	15.00	20.00	0.984	31.03	5.40	0.024	0.132	0.035	39.3	8.9	2.5	51.7	1DT17
1DT18	4:1	10	35.64	11.28	888.0	94.60	1.00	0.75	26.67	25.00	20.00	0.984	22.16	6.43	0.022	0.194	0.036	41.5	8.5	1.0	51.6	1DT18

Table 5.4a

Summary of CO2-N2 WAG Experiments in a Linear Model (Cont'd)

Run No.	WAG Ratio	No. of Slugs	Average Porosity {Ø} (%)	Average Perm. {k} (darcies)	Oil Vis. {μ} (mPa.s)	Oil Sat. {Soi} (%)	Expt. Press. {p} (MPa)	CO2 Press. {pco2} (MPa)	CO2-N2 Volume Injected (%HCPV)	%N2 in Mix.	CO2 Volume Injected (%HCPV)	Ave. Flow Vel. (m/d)	CO2-N2		Average WAG Production Rate (cc/sec)			Recovery (%HCPV)				Run No.
													Retention (%Inj.)	Requirement (sm3/sm3)	Oil	Gas	Water	WAG	PWF	BD	Total	
1DT19	4:1	10	35.91	10.99	888.0	95.21	1.00	0.70	28.57	30.00	20.00	0.984	4.06	6.42	0.021	0.194	0.037	42.1	7.1	2.1	51.3	1DT19
1DT20	4:1	10	35.61	8.89	888.0	95.57	1.00	0.95	50.00	4.98	47.51	0.984	38.23	10.27	0.015	0.136	0.044	51.2	3.2	2.7	57.1	1DT20
1DT21	4:1	10	35.93	11.45	888.0	94.66	1.00	0.90	40.00	9.99	36.00	0.984	27.31	8.27	0.021	0.131	0.048	49.4	4.7	2.1	56.2	1DT21
1DT22	4:1	10	35.83	11.05	888.0	94.16	1.00	0.85	40.00	15.00	34.00	0.984	17.58	8.48	0.020	0.150	0.041	46.8	4.7	3.3	54.8	1DT22
1DT23	4:1	10	35.73	11.22	888.0	94.92	1.00	0.90	20.00	9.99	18.00	0.984	38.35	4.24	0.026	0.101	0.039	37.3	13.9	3.2	54.4	1DT23
1DT24	4:1	10	35.59	10.90	888.0	94.89	1.00	0.85	40.00	15.00	34.00	0.984	35.35	8.41	0.020	0.150	0.041	46.8	5.1	2.6	54.5	1DT24
1DT25	4:1	10	35.45	9.44	888.0	95.99	1.00	0.95	20.00	4.98	19.00	0.984	37.53	4.84	0.026	0.230	0.034	36.3	9.2	2.9	48.4 (?)	1DT25
1DT16	4:1	10	37.57	11.35	888.0	94.77	1.00	0.95	30.00	4.98	28.51	0.984	57.72	6.48	0.020	0.209	0.038	42.0	3.7	2.2	47.9 (?)	1DT16
1DT27	4:1	10	36.06	9.80	888.0	97.70	1.00	0.95	21.05	4.98	20.00	0.984	34.47	5.19	0.038	0.339	0.033	37.8	6.7	4.0	48.5 (?)	1DT27
1DT28	4:1	10	35.77	11.12	888.0	95.32	1.00	0.90	40.00	9.99	36.00	0.984	42.60	7.89	0.021	0.214	0.048	50.2	6.0	3.4	59.6 (?)	1DT28
1DT29	4:1	10	35.77	10.61	888.0	94.48	1.00	0.85	20.00	15.00	17.00	0.984	29.35	4.21	0.028	0.205	0.031	39.1	17.1	3.0	59.2 (?)	1DT29
1DT30	4:1	10	32.22	11.82	1058.0	94.32	1.00	0.95	20.00	4.98	19.00	0.984	49.23	7.12	0.022	0.073	0.031	21.3	11.1	1.1	33.5 (?)	1DT30
1DT31	4:1	10	37.05	11.05	1058.0	94.98	1.00	0.85	20.00	15.00	17.00	0.984	23.98	4.31	0.026	0.074	0.035	36.8	11.9	4.2	52.9 (?)	1DT31
1DT32	4:1	10	35.64	11.02	1058.0	95.21	1.00	0.80	20.00	20.00	16.00	0.984	14.44	6.42	0.019	0.114	0.038	24.1	9.5	2.3	35.9 (?)	1DT32

Note: The oil used in all experiments was dead oil.

? - Misrun due to mechanical problems WAG = Water-Alternating-Gas PWF = Post-Waterflood BD = Blowdown

Total Recovery = WAG Recovery + PWF Recovery + BD Recovery

Table 5.4b

Summary of CO2-N2 WAG Experiments in a Two-Dimensional Model

Run No.	WAG Ratio	No. of Slugs	Average Porosity (Ø) (%)	Average Perm. (k) (darcies)	Oil Vis. (μ) (mPa.s)	Oil Sat. (Soi) (%)	Expt. Press. (p) (MPa)	CO2 Press. (pco2) (MPa)	CO2-N2 Volume Injected (%HCPV)	%N2 in Mix.	CO2 Volume Injected (%HCPV)	Ave. Flow Vel. (m/d)	CO2-N2 Retention (%Inj.)	CO2-N2 Requirement (sm3/sm3)	Average WAG Production Rate (cc/sec) Oil	Gas	Water	Recovery (%HCPV) WAG	PWF	BD	Total	Run No.
2DT1	4:1	10	40.77	11.14	1058.0	88.82	1.00	0.95	20.00	4.98	19.00	2.600	56.89	5.58	0.025	0.067	0.033	34.4	8.5	2.4	45.3	2DT1
2DT2	4:1	10	40.14	11.12	1058.0	89.51	1.00	0.90	20.00	9.99	18.00	2.600	44.74	5.64	0.025	0.104	0.036	34.7	7.2	2.9	44.8	2DT2
2DT3	4:1	10	39.48	11.22	1058.0	89.93	1.00	0.85	20.00	15.00	17.00	2.600	41.51	5.66	0.025	0.110	0.031	36.7	6.0	2.0	44.7	2DT3
2DT4	4:1	10	37.16	12.79	1058.0	90.14	1.00	0.80	20.00	20.00	16.00	2.600	38.70	5.75	0.024	0.127	0.035	33.4	6.0	2.5	41.9	2DT4
2DT5	4:1	10	38.00	14.04	1058.0	89.95	1.00	0.75	20.00	25.00	15.00	2.600	38.54	5.87	0.024	0.126	0.031	34.2	7.2	0.9	42.3	2DT5
2DT6	4:1	10	38.25	12.96	1058.0	92.30	1.00	0.70	20.00	30.00	14.00	2.600	38.52	5.95	0.024	0.126	0.031	34.1	6.6	0.9	41.6	2DT6
2DT7	4:1	10	40.44	11.79	1058.0	88.98	1.00	0.95	20.00	4.98	19.00	2.600	57.13	5.56	0.025	0.067	0.032	34.9	7.4	2.7	45.1	2DT7
2DT8	4:1	10	37.71	11.61	1058.0	88.11	1.20	1.00	20.00	15.00	17.00	2.600	56.01	3.60	0.027	0.075	0.034	38.4	11.5	2.4	52.3	2DT8
2DT9	4:1	10	38.60	11.17	1058.0	87.04	1.25	1.00	20.00	20.00	16.00	2.600	67.13	6.26	0.022	0.059	0.036	32.0	11.4	2.5	46.0	2DT9
2DT10	4:1	10	38.80	11.91	1058.0	88.60	1.44	1.00	20.00	30.00	14.00	2.600	53.52	7.87	0.022	0.097	0.039	31.7	11.1	2.6	45.4	2DT10
2DT11	4:1	10	40.17	10.94	1058.0	89.00	1.00	0.95	20.00	4.98	19.00	2.600	8.03	6.13	0.026	0.117	0.039	28.3	7.4	2.4	38.1 (?)	2DT11
2DT12	4:1	10	40.59	11.83	1058.0	88.82	1.00	0.85	20.00	15.00	17.00	2.600	16.37	5.18	0.026	0.119	0.031	37.0	7.9	3.1	48.0 (?)	2DT12
2DT13	4:1	10	39.31	11.86	1058.0	90.50	1.00	0.80	20.00	20.00	16.00	2.600	18.56	5.29	0.027	0.094	0.031	38.1	4.8	3.7	46.6 (?)	2DT13
2DT14	4:1	10	40.20	11.43	1058.0	89.45	1.00	0.75	20.00	25.00	15.00	2.600	38.54	4.93	0.025	0.102	0.032	35.1	10.5	4.1	49.7 (?)	2DT14

Note: The oil used in all experiments was dead oil.

? - Misrun due to mechanical problems　　WAG = Water-Alternating-Gas　　PWF = Post-Waterflood　　BD = Blowdown

Total Recovery = WAG Recovery + PWF Recovery + BD Recovery

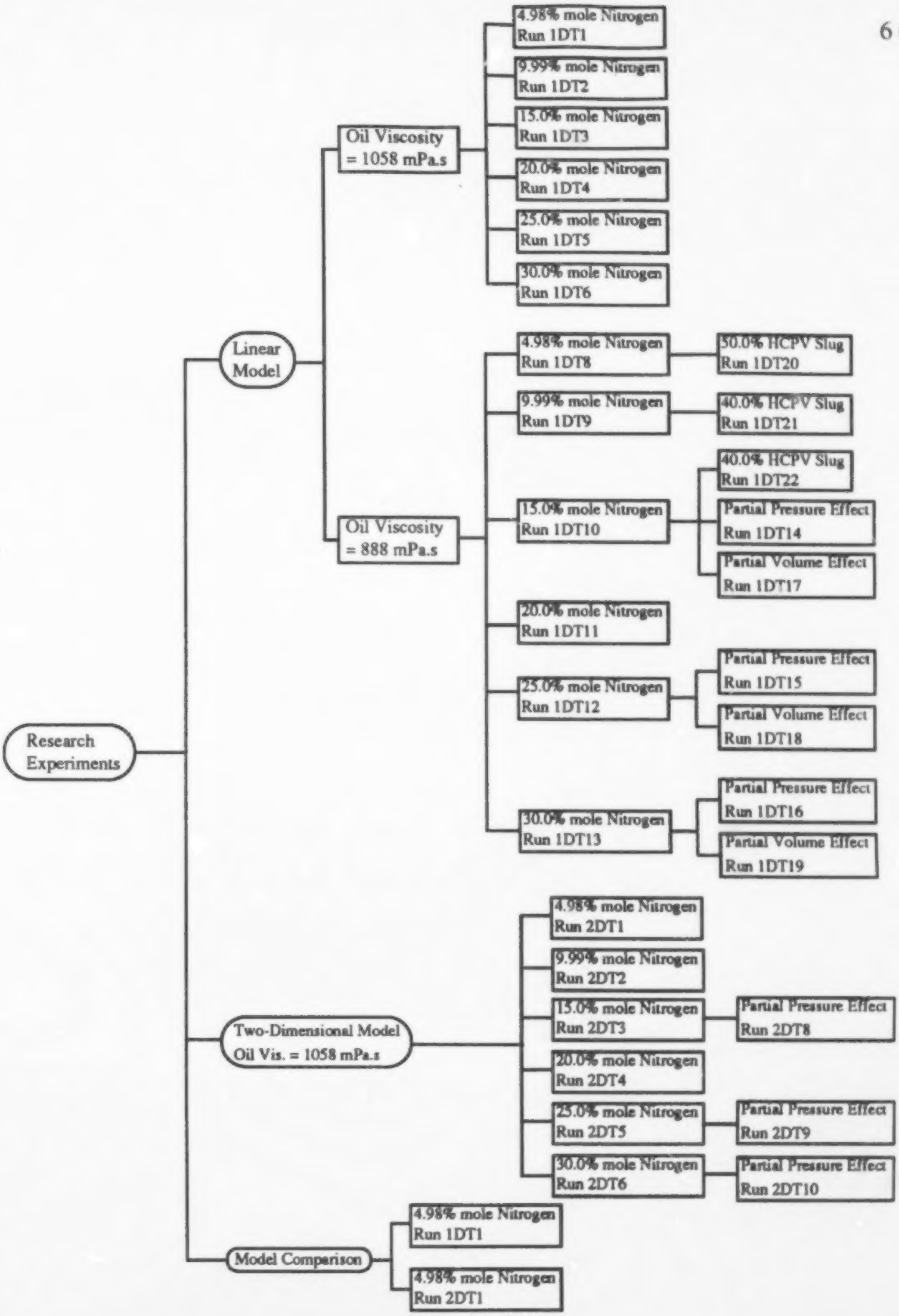

Research Experiments
Linear Model
Oil Viscosity = 1058 mPa.s
4.98% mole Nitrogen Run 1DT1
9.99% mole Nitrogen Run 1DT2
15.0% mole Nitrogen Run 1DT3
20.0% mole Nitrogen Run 1DT4
25.0% mole Nitrogen Run 1DT5
30.0% mole Nitrogen Run 1DT6
Oil Viscosity = 888 mPa.s
4.98% mole Nitrogen Run 1DT8
50.0% HCPV Slug Run 1DT20
9.99% mole Nitrogen Run 1DT9
40.0% HCPV Slug Run 1DT21
15.0% mole Nitrogen Run 1DT10
40.0% HCPV Slug Run 1DT22
Partial Pressure Effect Run 1DT14
Partial Volume Effect Run 1DT17
20.0% mole Nitrogen Run 1DT11
25.0% mole Nitrogen Run 1DT12
Partial Pressure Effect Run 1DT15
Partial Volume Effect Run 1DT18
30.0% mole Nitrogen Run 1DT13
Partial Pressure Effect Run 1DT16
Partial Volume Effect Run 1DT19
Two-Dimensional Model Oil Vis. = 1058 mPa.s
4.98% mole Nitrogen Run 2DT1
9.99% mole Nitrogen Run 2DT2
15.0% mole Nitrogen Run 2DT3
Partial Pressure Effect Run 2DT8
20.0% mole Nitrogen Run 2DT4
25.0% mole Nitrogen Run 2DT5
Partial Pressure Effect Run 2DT9
30.0% mole Nitrogen Run 2DT6
Partial Pressure Effect Run 2DT10
Model Comparison
4.98% mole Nitrogen Run 1DT1
4.98% mole Nitrogen Run 2DT1

Figure 5.3 - Map of Experiments Conducted.

5.3.1 Pure Carbon Dioxide Experiments

Linear Model Experiments

In this section, the previous work[9,11] using pure carbon dioxide will be analyzed to observe the salient aspects of the process.

5.3.1.1 Effect of Operating Pressure

The pressure at which the immiscible carbon dioxide WAG (Water-Alternating-Gas) process is carried out is very important in the evaluation of the process efficiency. At high pressures, carbon dioxide has a smaller volume, is more soluble in oil, and has a higher diffusivity than at low pressures. As a result, greater oil swelling and viscosity reduction will occur. Furthermore, at higher pressures, the mobility of carbon dioxide is lower because of increased viscosity.

Runs LC19D[9], LC31[11], and LC42[11] (see Table 3.4) were conducted at 5.5 MPa, 2.5 MPa, and 1.0 MPa, respectively, to study the effect of the operating pressure on the process efficiency. All other experimental parameters and conditions were the same.

Figure 5.4 depicts the comparison of the producing GOR's for these runs. The producing GOR in Run LC19D[9] tends to be lower than those in Runs LC31[11] and LC42[11], as shown. This is so because, at 5.5 MPa, more of the injected carbon dioxide is dissolved in oil than at 2.5 MPa and 1.0 MPa. As a result, the free gas saturation was much smaller in Run LC19D[9] than in Runs LC31[11] and LC42[11]. Under immiscible conditions, there is always free carbon dioxide gas because there is insufficient time for the injected carbon dioxide to dissolve and diffuse into the oil because of the immediate injection of water following the injection of carbon dioxide. Under some conditions, the free carbon dioxide may segregate and form a free gas zone. When water is injected, it will not only mobilize the carbon dioxide-saturated oil, but also the free carbon dioxide gas. This mobilization of the free carbon dioxide gas is indicated by the producing GOR curves of Runs LC31[11] and LC42[11]. High GOR's were recorded in these two runs since large volumes of gas were collected. The volume of the produced gas was the volume of the free gas plus that of the dissolved gas. This total volume was used to calculate the producing GOR's.

The effect of the operating pressure on the oil recovery is considered to be the most significant in the immiscible carbon dioxide WAG process. To examine this effect, the production histories of all three runs were plotted in Figure 5.5. Among the three runs,

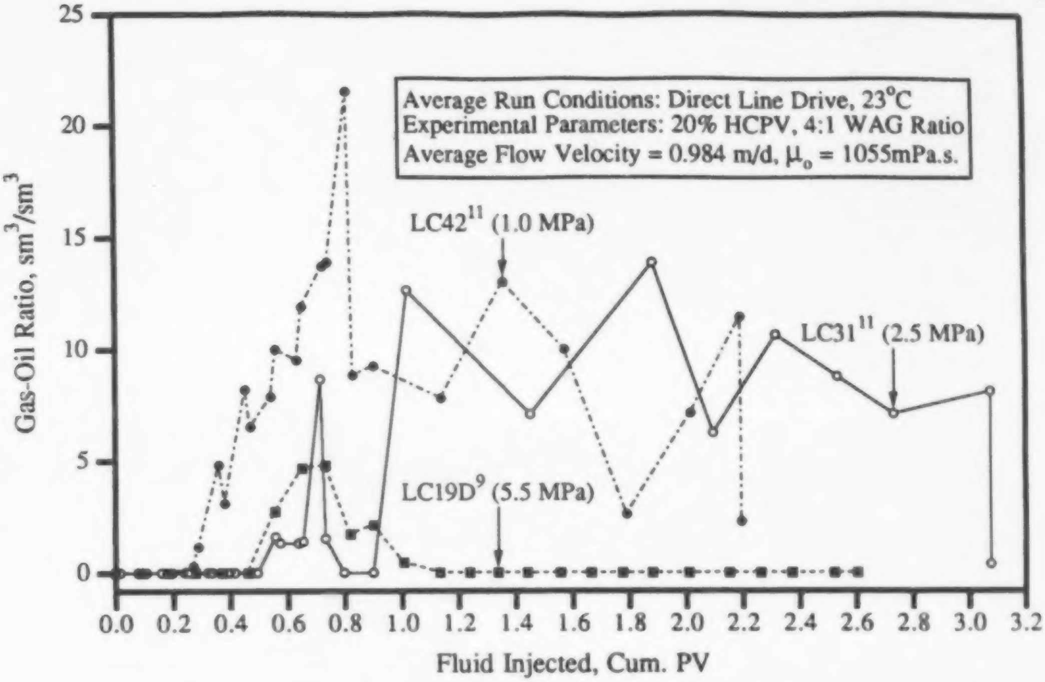


Figure 5.4 - Effect of Pressure on Producing GOR (Data From Refs. 9 & 11).

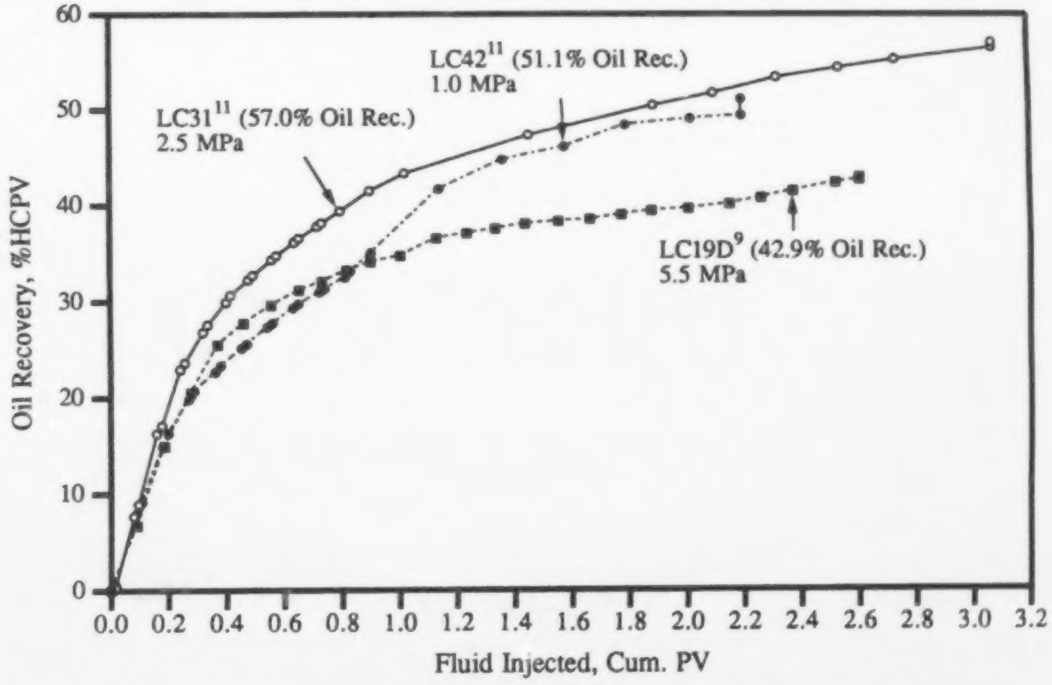


Figure 5.5 - Effect of Pressure on Oil Recovery (Data From Refs. 9 & 11).

Run LC31[11], conducted at 2.5 MPa, produced the highest recovery, 57.0%; Run LC42[11], at 1.0 MPa, the second highest recovery, 51.1%; and Run LC19D[9], at 5.5 MPa, the lowest recovery, 42.9%. When carbon dioxide dissolves in a Lloydminster heavy oil, it causes the precipitation of the solid asphaltenes[55-63]. It is worth noting that the amount of asphaltenes precipitated depends on the carbon dioxide solubility in oil. For Aberfeldy heavy oil, asphaltene precipitates when carbonation pressure is greater than 3.5 MPa[63]. Therefore, it is believed that asphaltene precipitation occurred in Run 19D[9], conducted at 5.5 MPa. In this run, asphaltene particles plugged the pore channels, reducing the sand pack permeability, blocked the flow of the fluids, thus causing injectivity and productivity problems. Oil, because of its much higher viscosity and lower mobility than water, was affected the most. In other words, it was trapped by the asphaltene particles. Water, being more mobile than oil, could still flow through the partially blocked pore space, bypassing the oil. This effect can be seen in Figure 5.6, where the producing WOR's for all three runs are plotted. The producing WOR curve of Run LC19D[9] is much higher than those of Runs LC31[11] and LC42[11], indicating that more water than oil was produced in this run. The WOR of Run LC19D[9] reached a value as high as 55.0 sm^3/sm^3, which is about two times higher than those for Runs LC31[11] and LC42[11]. Also, in Run LC19D[9], the limiting WOR of 20:1 was reached earlier than in Runs LC31[11] and LC42[11]. That is why a low oil recovery was obtained in this run.

In addition to the effect on recovery, the operating pressure also affects the carbon dioxide requirement and retention. Figure 5.7 illustrates on the comparison of the carbon dioxide requirements and retentions for Runs LC19D[9], LC31[11] and LC42[11], showing that the carbon dioxide requirement and retention increased with increasing pressure due to increased solubility.

5.3.1.2 Effect of Solution Gas

To observe the effect of solution gas on the efficiency of the immiscible WAG process, Run LC40[11] was conducted using a live oil sample. As previously mentioned, live oil was prepared by mixing methane gas with dead oil at the experimental conditions, i.e. 1.0 MPa and 23°C. The original viscosity of dead oil was 1,046.0 mPa.s. After solution of methane, its viscosity was reduced to 784.0 mPa.s. This viscosity value was estimated using the correlation of Singh et al.[95]. Appendix B provides a sample calculation of live oil viscosity.

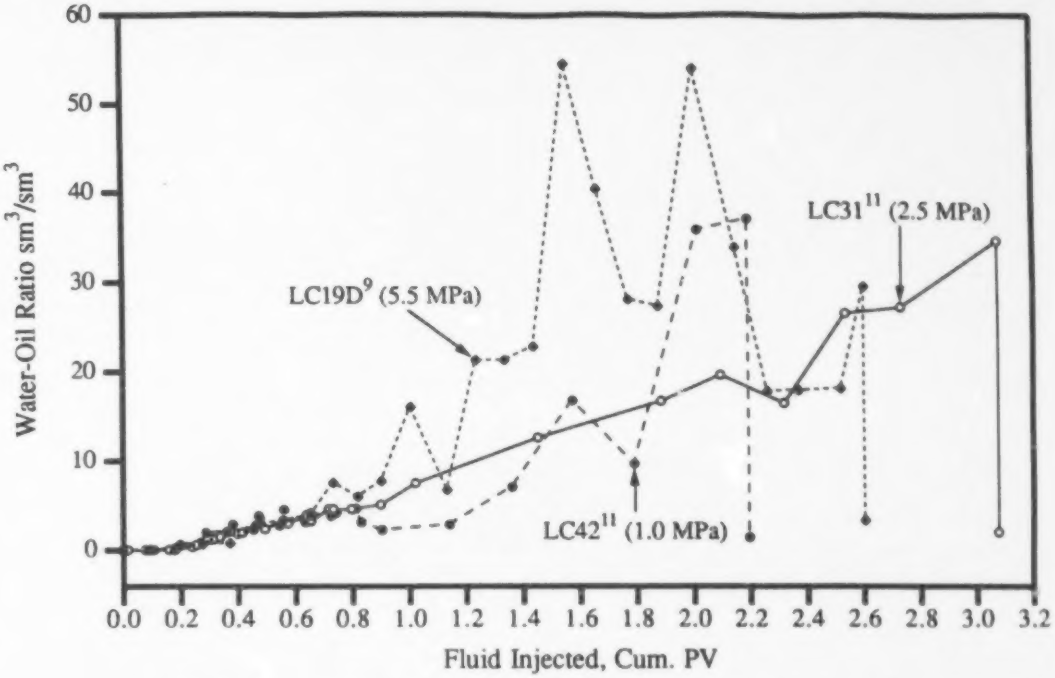


Figure 5.6 - Comparison of Producing WOR's of Runs LC19D[9], LC31[11], and LC42[11] (Data From Refs. 9 & 11).

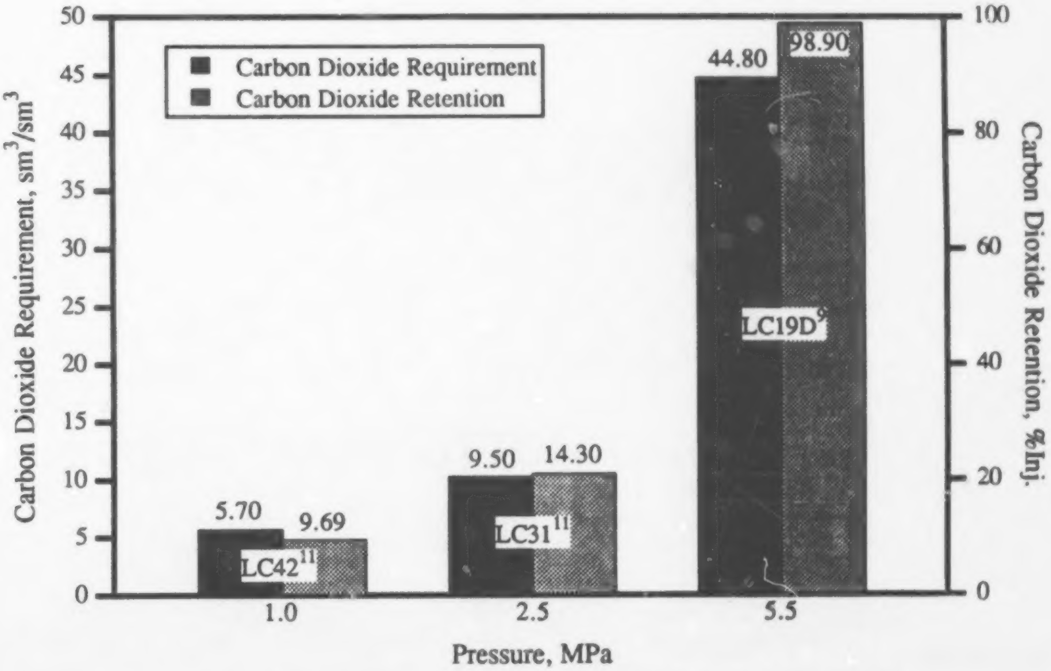
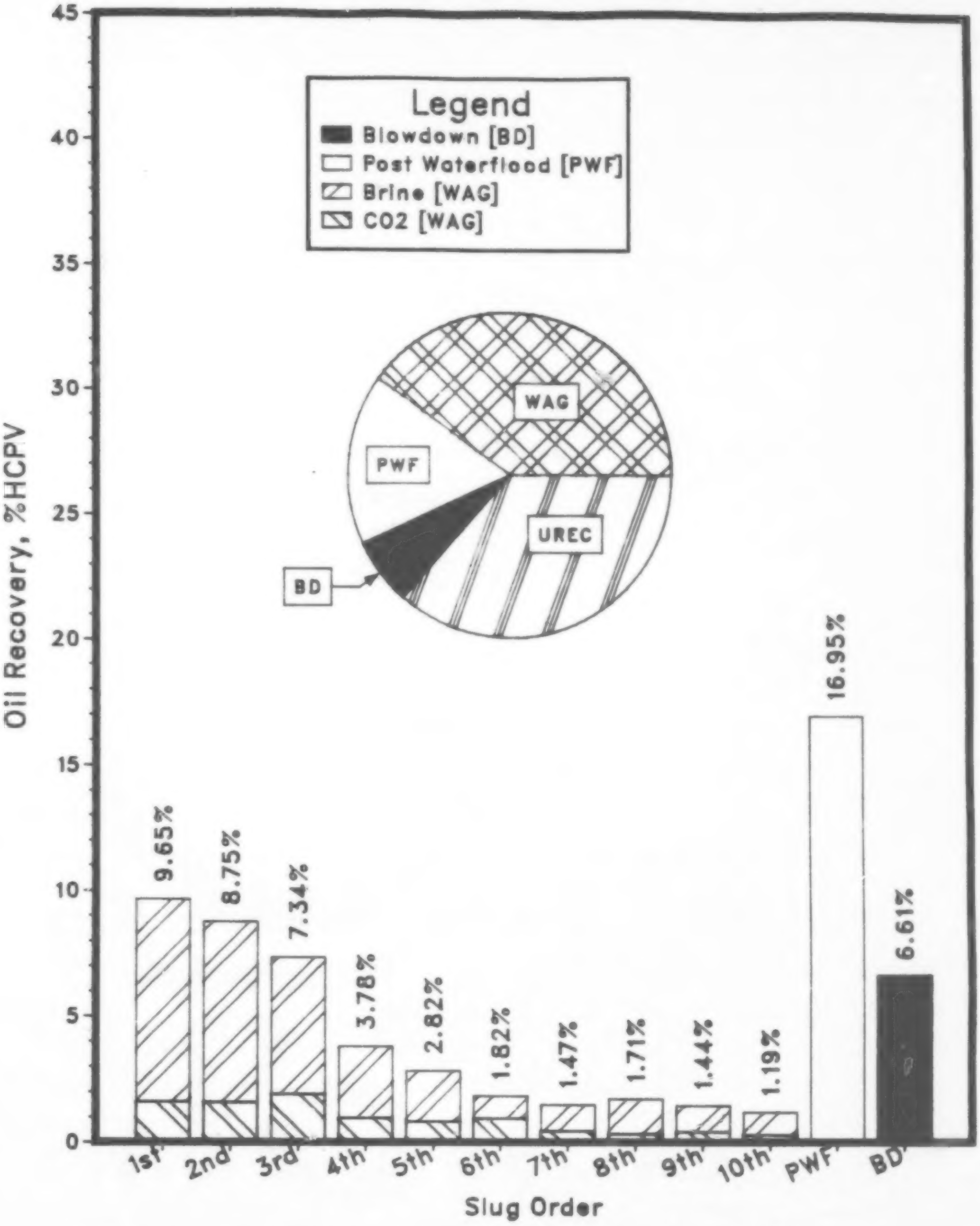


Figure 5.7 - Effect of Pressure on Carbon Dioxide Requirement and Carbon Dioxide Retention (Data From Refs. 9 & 11).

Figure 5.8 and 5.9 provide the slug recovery and production history of Run LC40[11], respectively. A comparison of the performance of this run with that of Run LC42[11] (conducted using dead oil) is shown in Figure 5.10. It is seen that, at any stage of the process, Run LC40[11] performed better than Run LC42[11]. This is supported by the oil recovery noted at each stage. The overall recovery in Run LC40[11] was 12.4% higher than that in Run LC42[11]. This increased recovery was mainly due to the solution gas which provided an extra internal drive to mobilize oil while water was exerting an external drive and carbon dioxide was diffusing into oil. In other words, a solution gas drive mechanism was also active in Run LC40[11]. As well, the initial viscosity of the live oil used in Run LC40[11] was lower by 262 mPa.s. Besides, the blowdown recovery in Run LC40[11] was about four times higher than that in Run LC42[11]. This large blowdown recovery was basically due to the solution gas plus diffused carbon dioxide which came out of the oil when pressure was being lowered to the atmospheric pressure, thus providing a driving force that helped to mobilize oil towards the production well. In contrast, in Run LC42[11], only diffused carbon dioxide was released from oil. Based upon this, it is speculated that the volume of gas liberated was much greater in Run LC40[11]. As a result, a higher blowdown recovery was achieved.

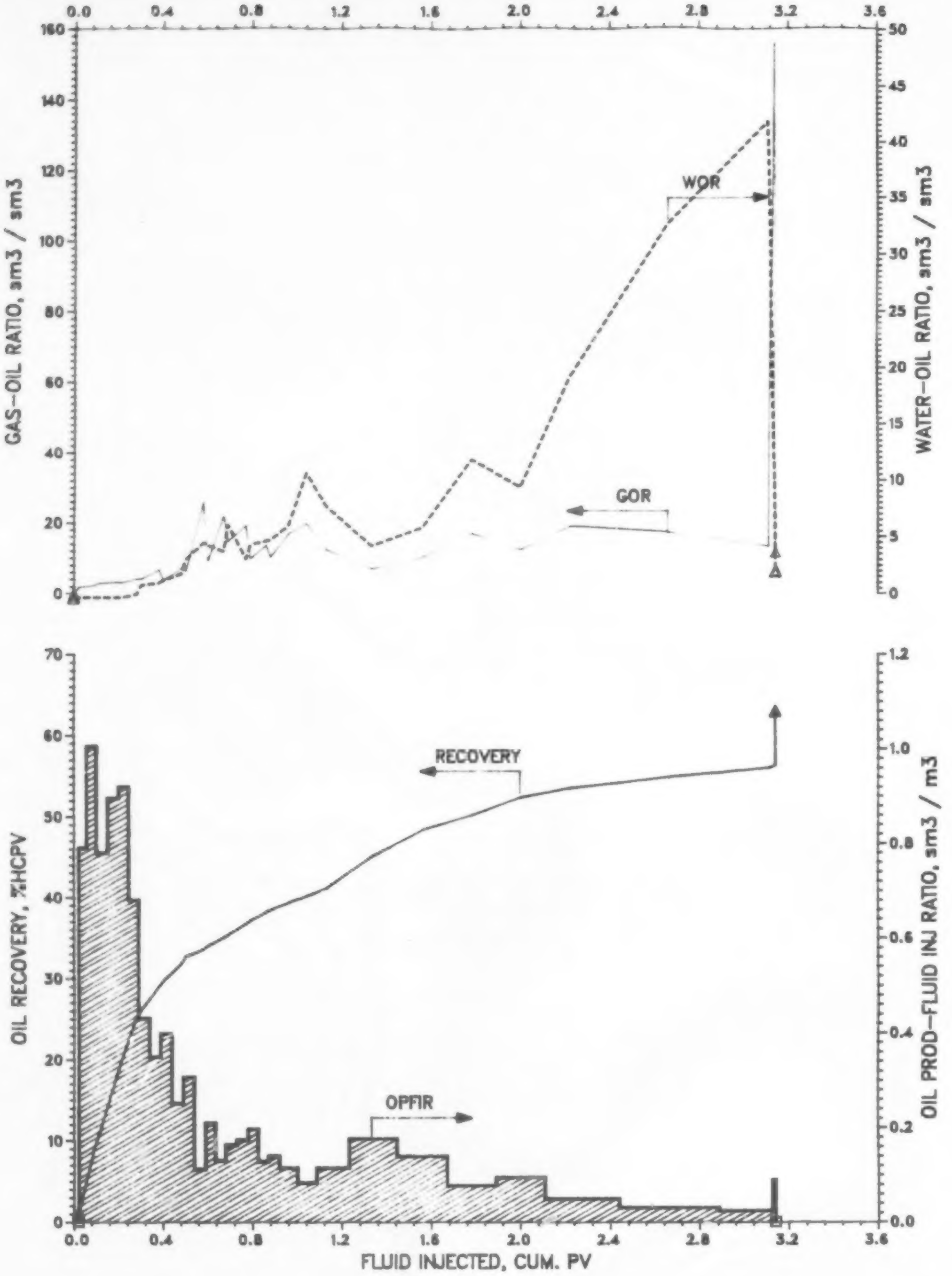
Figures 5.11 and 5.12 provide a comparison of the producing GOR's and WOR's of Runs LC40[11] and LC42[11], respectively. The two producing GOR curves in Figure 5.11 shows that gas was immediately produced after injection was started in Run LC40[11] and more gas was produced in this run than in Run LC42[11]. Possible explanations for this occurrence are that initially live oil was produced, thus at the very beginning of the injection, only methane gas was produced; and that when carbon dioxide dissolved in oil, it displaced methane from the oil, thus creating a free gas zone which fingered through the oil. Therefore, as injection was continued, volumes of carbon dioxide and methane mixture were produced. This is why, from the start to finish, more gas was produced in Run LC40[11], which also had lower producing WOR's than Run LC42[11], as shown in Figure 5.12. This indicates that more oil was produced in this run, and a lower oil-to-water viscosity ratio and improved mobility control of the fluids were operating. Better mobility control in Run LC40[11] was mainly due to the solution gas in oil which contributed to the reduction in the oil-water interfacial tension, promoting the formation of water-in-oil emulsions, which tended to damp out the viscous fingering of water in oil, leading to a better volumetric sweep. Better mobility control also determines the flood life. As demonstrated in Figures 5.11 and 5.12, Run LC40[11] had a longer flood life than Run LC42[11] since it took a longer time to reach the limiting WOR of 20:1.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s
ϕ = 35.70 %, k = 10.200 darcies, S_o = 94.10 %, S_{wc} = 5.90 %

[0.20 HCPV CO2 @ 1.0 MPa (0.091 g–mol) 4:1 WAG,10 Slugs, LIVE OIL]
Total Oil Recovery = 63.5% HCPV

Figure 5.8 – Oil Recovery Distribution of Run LC40, After Prosper [Ref. 11].



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s
ϕ = 35.70 %, k = 10.200 darcies, S_o = 94.10 %, S_{wc} = 5.90 %

[0.20 HCPV CO2 @ 1.0 MPa (0.091 g-mol) 4:1 WAG,10 Slugs, LIVE OIL]

Figure 5.9 – Production History of Run LC40, After Prosper [Ref. 11].

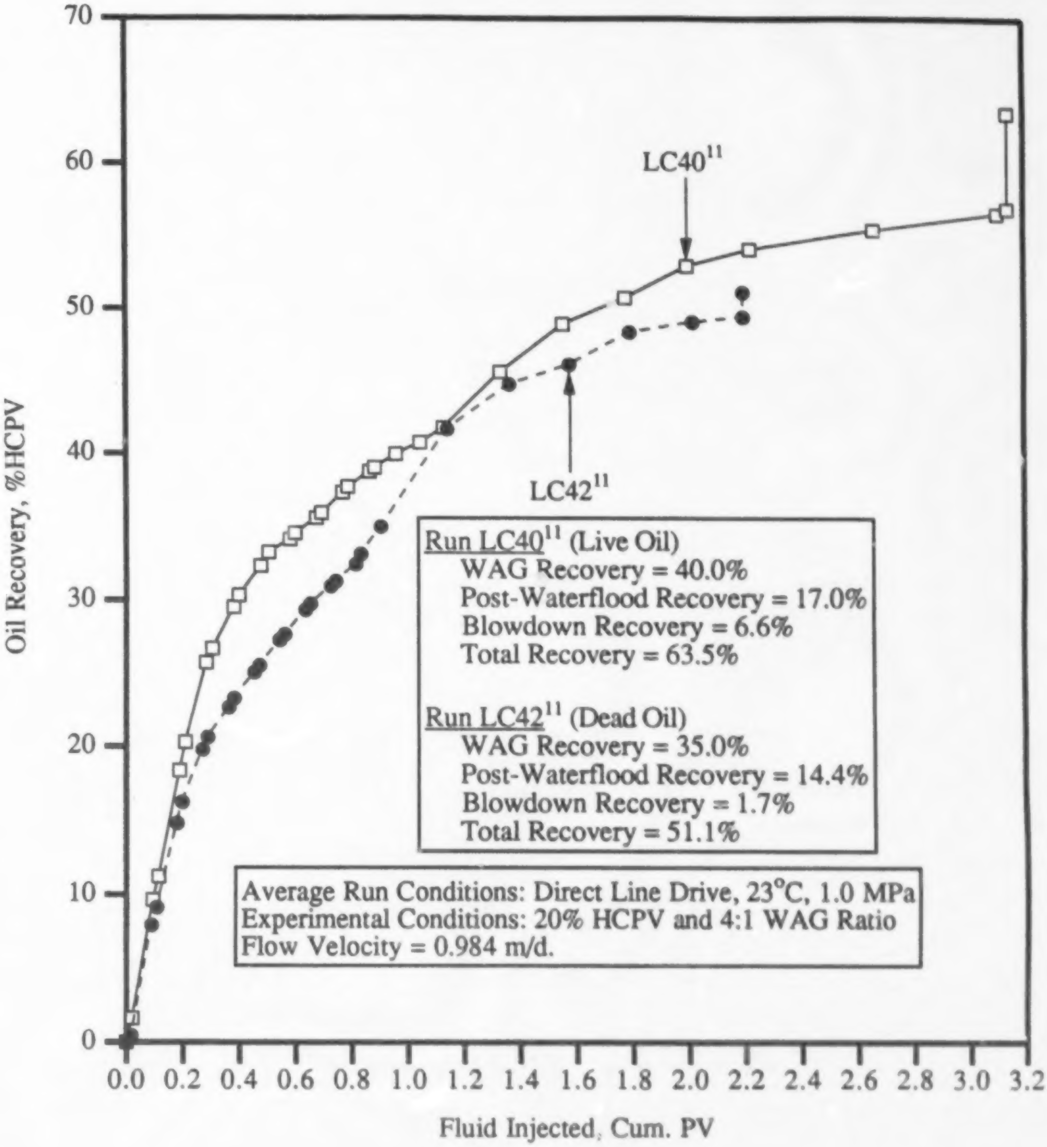


Figure 5.10 - Effect of Solution Gas on Recovery (Data From Ref. 11).

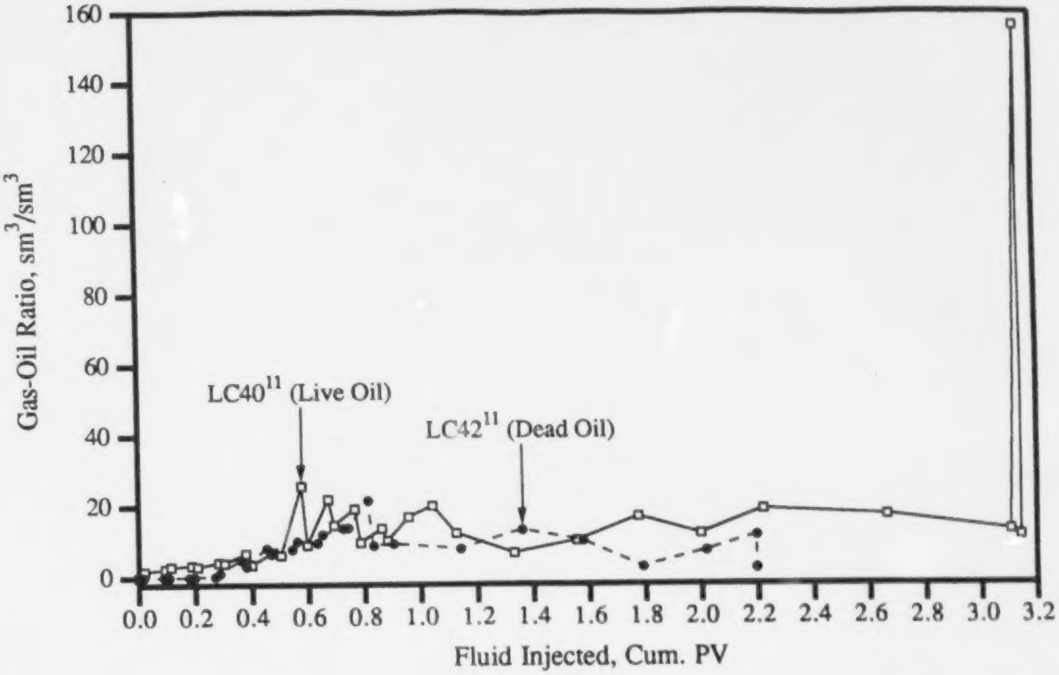


Figure 5.11 - Effect of Solution Gas on Producing GOR (Data From Ref. 11).

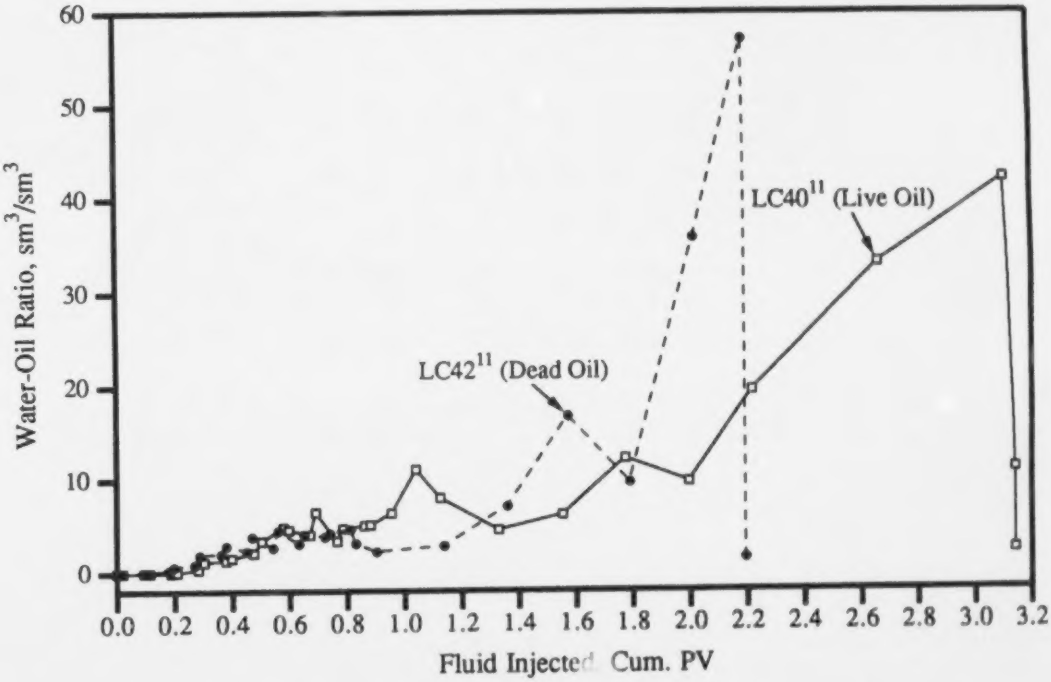


Figure 5.12 - Effect of Solution Gas on Producing WOR (Data From Ref. 11).

Summarizing, the presence of solution gas in oil increased the displacement efficiency of the process, leading to increased oil recovery.

Two-Dimensional Model Experiments

5.3.1.3 Effect of a Small Total Slug Size and a Large WAG Ratio

Run GTD1[11] was conducted at 2.5 MPa with a total slug size of 2% HCPV and a 40:1 WAG ratio. For ten equal slugs used, the volume of carbon dioxide injected per slug was about 0.2% HCPV. The oil recovered in the three stages of the process, i.e. WAG, post-waterflood, and blowdown, were 28.1, 4.4, and 0.4%, respectively, giving a total of 32.8%. Figure 5.13 provides the oil recovery distribution for this run.

Figure 5.14 shows the producing GOR for this run. It can be seen that since a very small total volume of carbon dioxide was injected, a very small volume of gas was correspondingly produced.

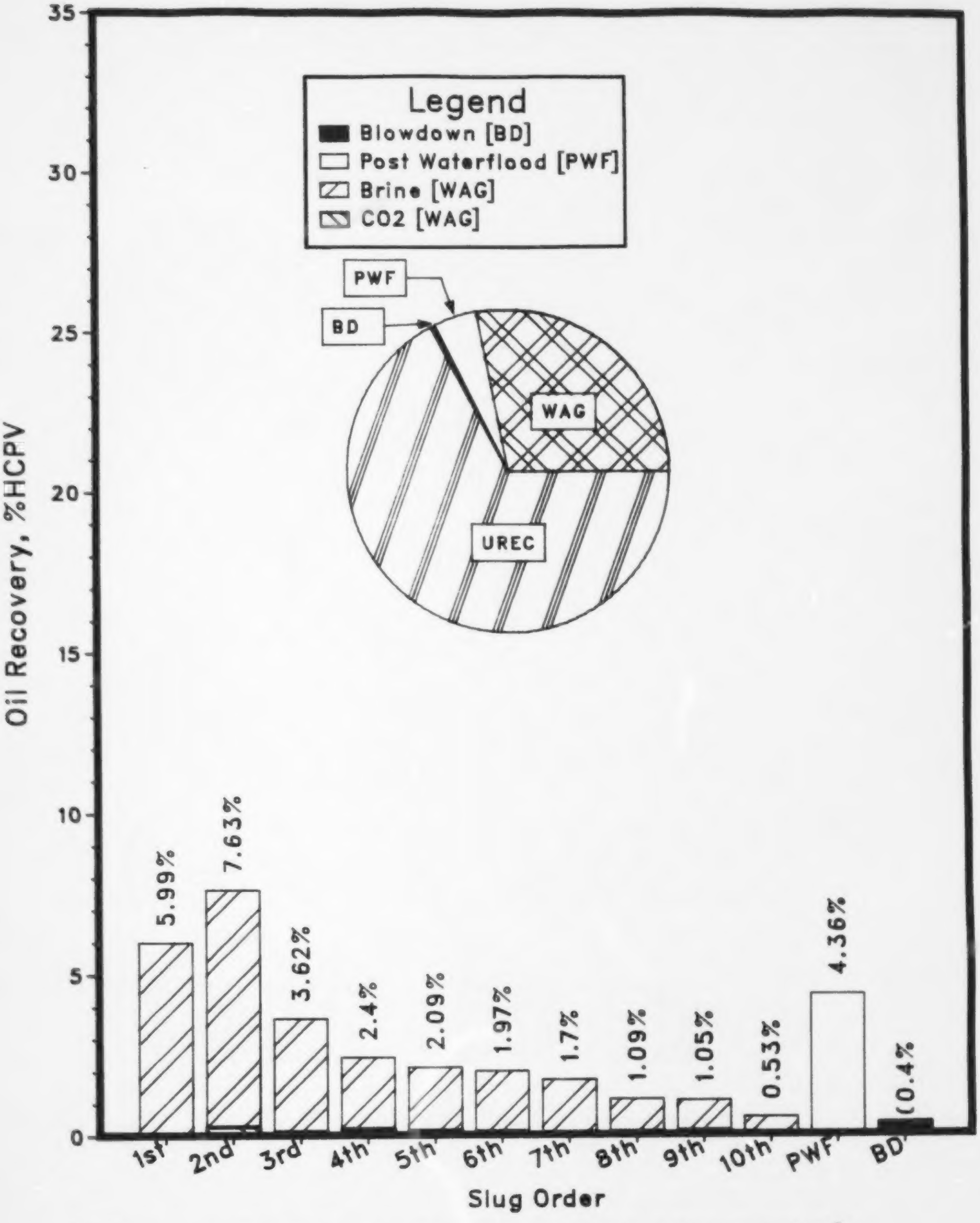
To examine how effectively the use of a small total gas slug size of 2% HCPV and a 40:1 WAG ratio recovered oil, a comparison of Run GTD1[11] with Run 11R[5], which was done primarily by waterflooding the model, was made and is provided in Figures 5.15 and 5.16.

Figure 5.15 shows that the producing WOR curve of Run GTD1[11] tended to be above that of Run 11R[5], which implies that , in Run GTD1[11], water displaced a highly viscous oil of the original viscosity (i.e. 1046 mPa.s). The reason is that since a very small total volume of carbon dioxide was injected, the oil viscosity remained high, i.e. there was very little or no reduction in oil viscosity in run GTD1[11]. As a result, water had to mobilize a very viscous oil, and a very high mobility ratio was encountered. Consequently, a low oil recovery resulted. This recovery is closely comparable to the low recovery obtained in Run 11R[5], the waterflood (Figure 5.16).

Based upon the above evidence, it can be concluded that the use of a small total gas slug size and a large WAG ratio is no more effective than a waterflood.

5.3.1.4 Effect of Flow Velocity

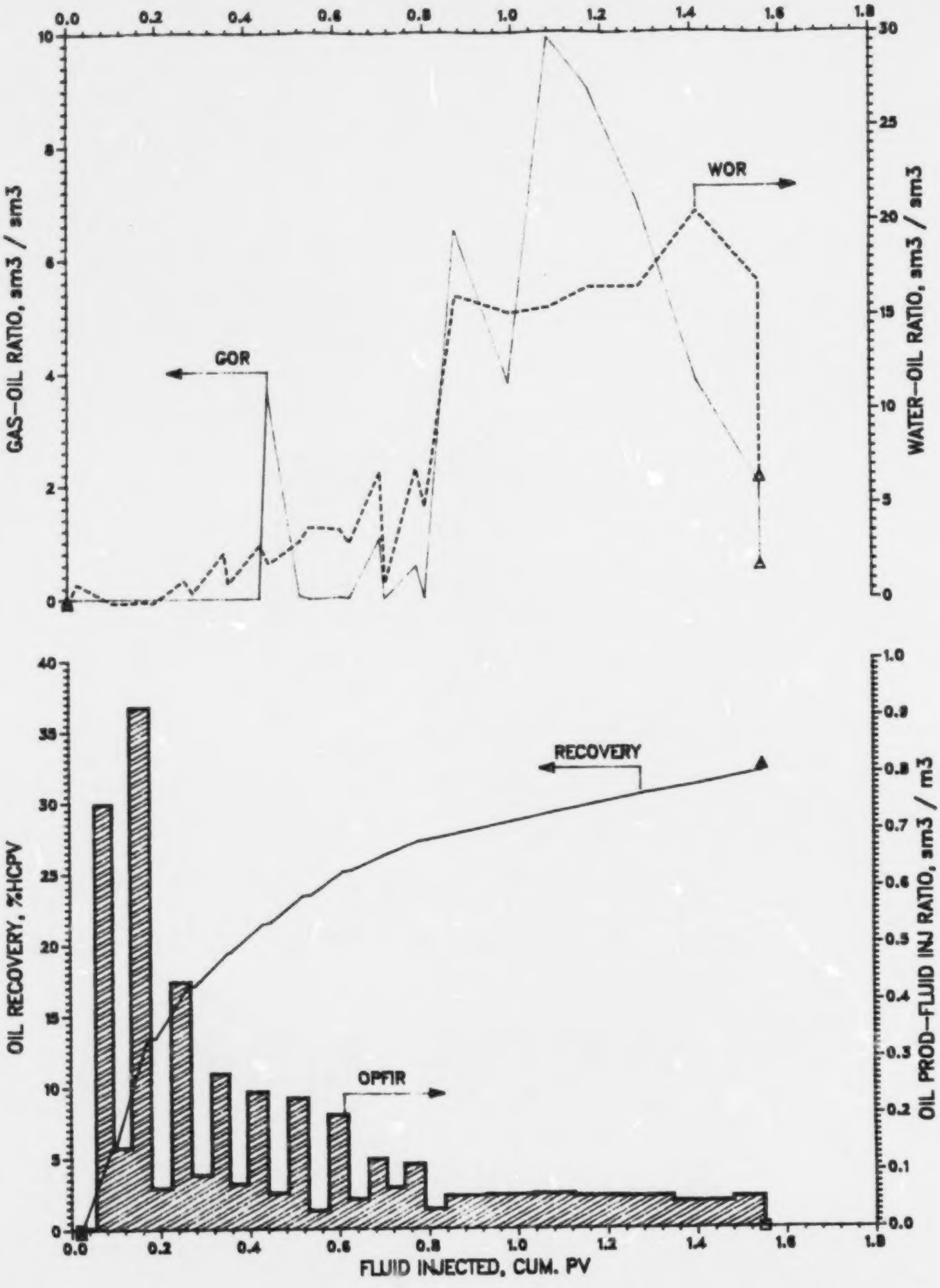
Three runs were conducted at three different flow velocities (rates) to investigate the effect of flow velocity. They were Runs 3D[9], GTD9[11], and GTD6[11]. The velocities used in



NOTE: Average Run Conditions: Quarter of a 5–Spot, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 1.290 m/d, μ_o = 1230.0 mPa.s
ϕ = 41.55 %, k = 13.6 darcies, S_o = 85.95 %, S_{wc} = 14.05 %

[0.02 HCPV CO2 @ 2.5 MPa (0.420 g–mol) 40:1 WAG,10 Slugs, DEAD OIL]
Total Oil Recovery = 32.8% HCPV

Figure 5.13 – Oil Recovery Distribution of Run GTD1, After Prosper [Ref. 11].



NOTE: Average Run Conditions: Quarter of a 5–Spot, 2.50 MPa and 23°C
Model Parameters: Average Flow Velocity = 1.290 m/d, μ_o = 1230.0 mPa.s
ϕ = 41.55 %, k = 13.6 darcies, S_o = 85.95 %, S_{wc} = 14.05 %

[0.02 HCPV CO2 @ 2.5 MPa (0.420 g–mol) 40:1 WAG,10 Slugs, DEAD OIL]

Figure 5.14 – Production History of Run GTD1, After Prosper [Ref. 11].

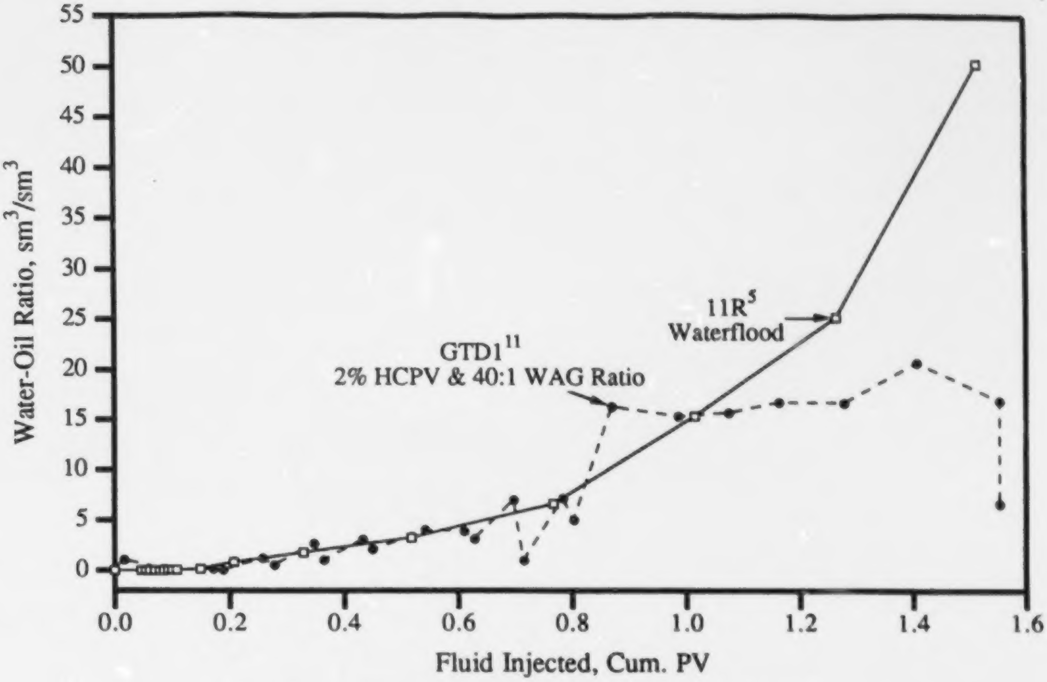


Figure 5.15 - Comparison of WOR's of Runs GTD1 and 11R
(Data From Refs. 5 & 11).

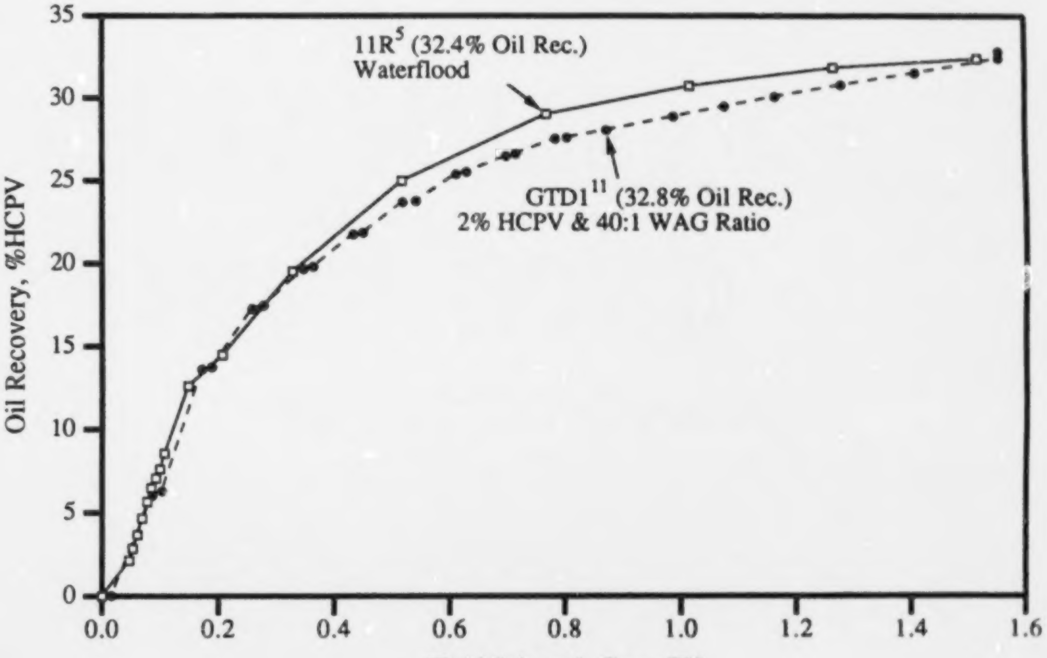


Figure 5.16 - Comparison of Recoveries of Runs GTD1 and 11R
(Data From Refs. 5 & 11).

these runs in increasing order were 0.83, 1.29, and 2.6 m/d, respectively. Both carbon dioxide and water were injected at the same injection velocity, and the same experimental parameters - a total gas slug size of 20% HCPV and 4:1 WAG ratio at 1.0 MPa and 23°C - were used in these runs.

Figure 5.17 compares the producing GOR's of Runs 3D[9], GTD9[11], and GTD6[11]. It can be seen from this figure that increasing gas velocity increased GOR's. This is basically due to the residence time. When carbon dioxide is injected at a low velocity, it has a longer time to diffuse into the oil phase. Also, the volumetric injection rate of carbon dioxide was lower at the lower velocity. In Run 3D[9], since carbon dioxide was injected at 0.83 m/d, the lowest of the three velocities used, it had the longest diffusion time, thus the highest carbon dioxide diffusion into oil. As a result of this, the oil viscosity reduction in Run 3D[9] was expected to be greater than those in Runs GTD9[11] and GTD6[11]. Because of greater diffusion and lower injectivity at a lower velocity, the breakthrough of the injected gas was delayed also. The breakthrough of carbon dioxide occurred at 0.728 PV in Run 3D[9], 0.659 PV in Run GDT9[11], and 0.44 PV in Run GDT6[11].

To see how effectively the use of different flow velocities (rates) affected the displacement of carbon dioxide-saturated oil by water, the cumulative producing WOR's of Runs 3D[9], GTD9[11], and GTD6[11] were plotted vs. oil recoveries in Figure 5.18. The curves show that less oil was displaced at the lower velocity and at a higher cumulative producing WOR than at the higher flow velocity. The total oil recovery for each run is shown in Figure 5.19. The cumulative recovery was 43.3% for Run 3D[9], 46.4% for Run GTD9[11], and 51.3% for Run GTD6[11]. An appropriate explanation for low recoveries in Runs 3D[9] and GTD9[11] is the effect of gravity segregation. At a very low flow velocity, the gravity effect is large. Since Runs 3D[9] and GTD9[11] were carried out with low flow velocities (0.83 and 1.29 m/d, respectively), the gravity effects in these two runs were quite large. Thus, the viscous force to gravitational force ratios (F_v/F_g) were too small in Runs 3D[9] and GTD9[11]. As a result, the water injected in these two runs, instead of displacing oil, segregated at the bottom of the model or flowed downward vertically to the bottom, which caused the displacing front to be nearly flat or horizontal. Therefore, only portions of oil near and at the bottom of the model were removed, resulting in a poor volumetric sweep and hence low oil recovery.

In contrast to Runs 3D[9] and GTD9[11], Run GTD6[11] was more successful since the effect of gravity segregation was reduced due to the high flow velocity. The displacement of carbon dioxide-saturated oil by water in this run is characterized by low cumulative

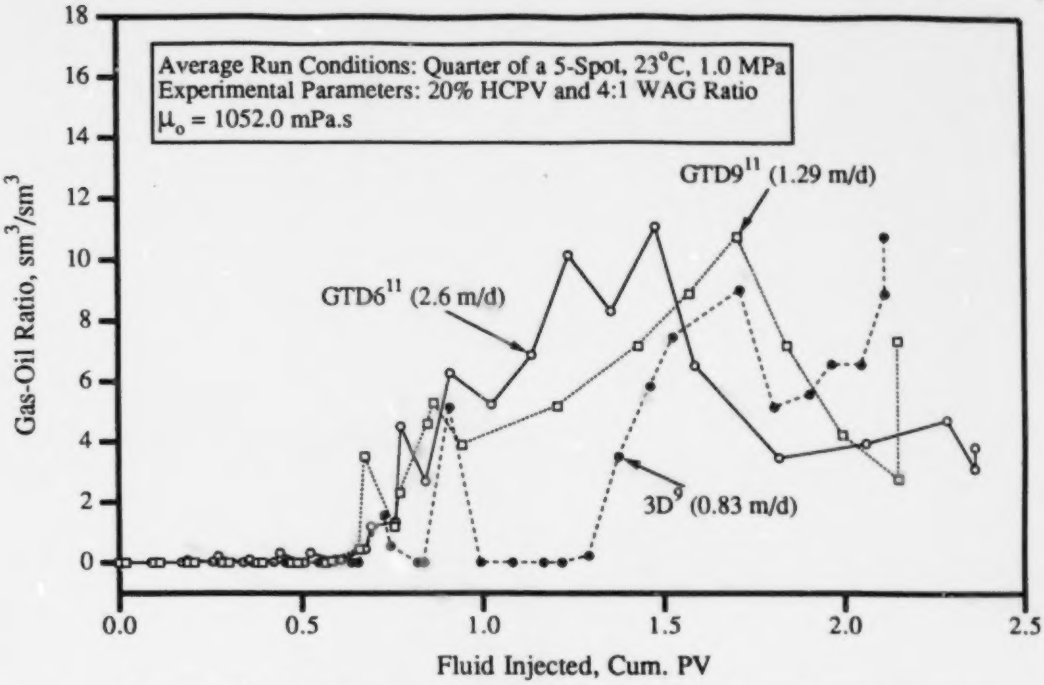


Figure 5.17 - Comparison of Producing GOR's at Different Flow Velocities (Data From Refs. 9 & 11).

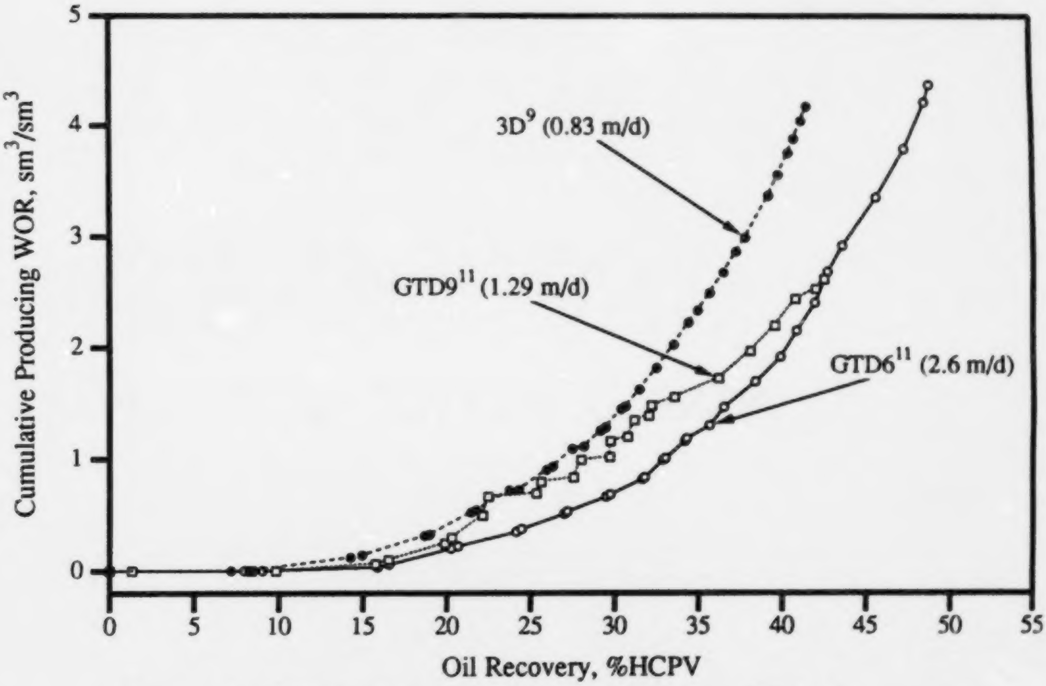


Figure 5.18 - Effect of Flow Velocity on Displacement Efficiency (Data From Refs. 9 & 11).

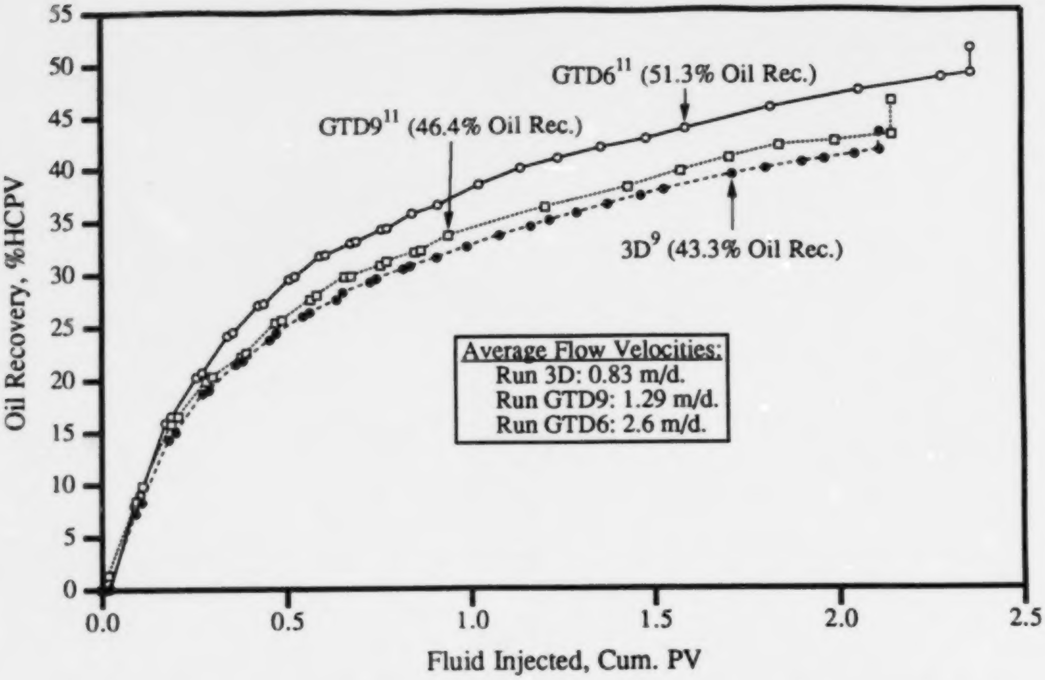


Figure 5.19 - Effect of Flow Velocity on Oil Recovery (Data From Refs. 9 & 11).

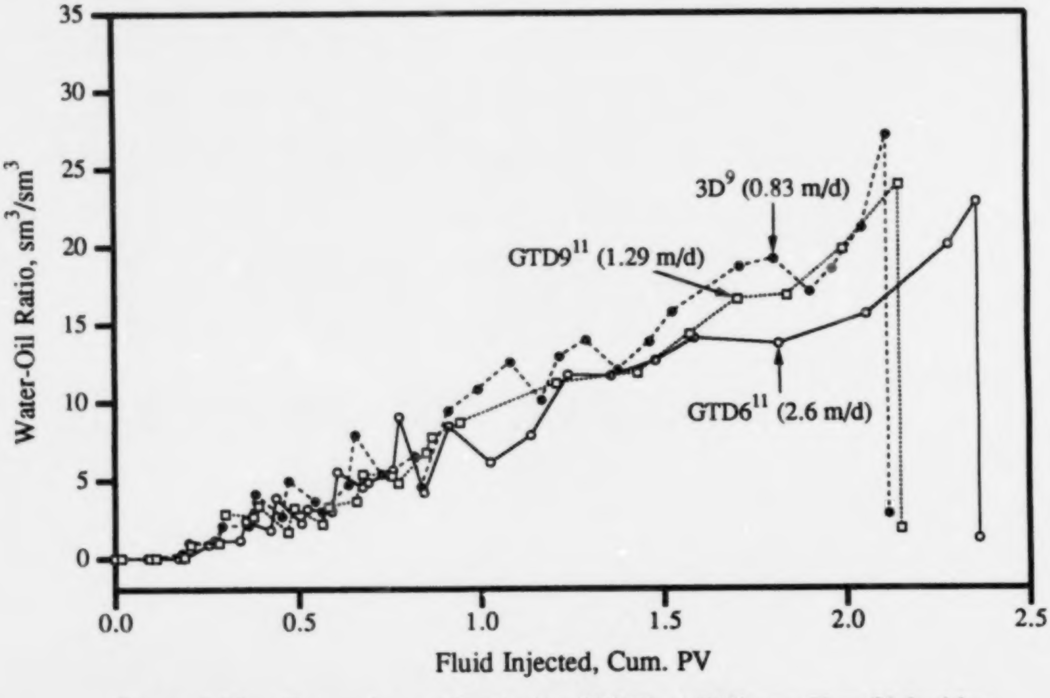


Figure 5.20 - Comparison of Producing WOR's at Different Flow Velocities (Data From Refs. 9 & 11).

producing WOR's (Figure 5.18) and a steep or nearly vertical displacing front. Thus, a very good sweep, as well as a high recovery, was obtained.

In addition to the above, the water flow velocity also affected the period of flooding. Figure 5.20 shows that the lower flow velocity resulted in the shorter flooding time since the limiting WOR reached earlier at the lower flow velocity. The flood lives of Runs 3D[9], GTD9[11], and GTD6[11] were, respectively, 2.12, 2.14, and 2.36 PV. Besides, early water breakthrough was also noted at the lower flow velocity. The breakthrough of water occurred at 0.182 PV in Run 3D[9], at 0.206 PV in Run GTD9[11], and at 0.256 PV in Run GTD6[11].

Thus, flow velocity is important in oil displacement by the immiscible WAG process. The use of a low injection velocity led to poor sweep efficiency and loss of recovery. A higher recovery could have been expected in Run 3D[9] if a higher water injection velocity, e.g 2.6 m/d, were used while the carbon dioxide injection velocity remained low.

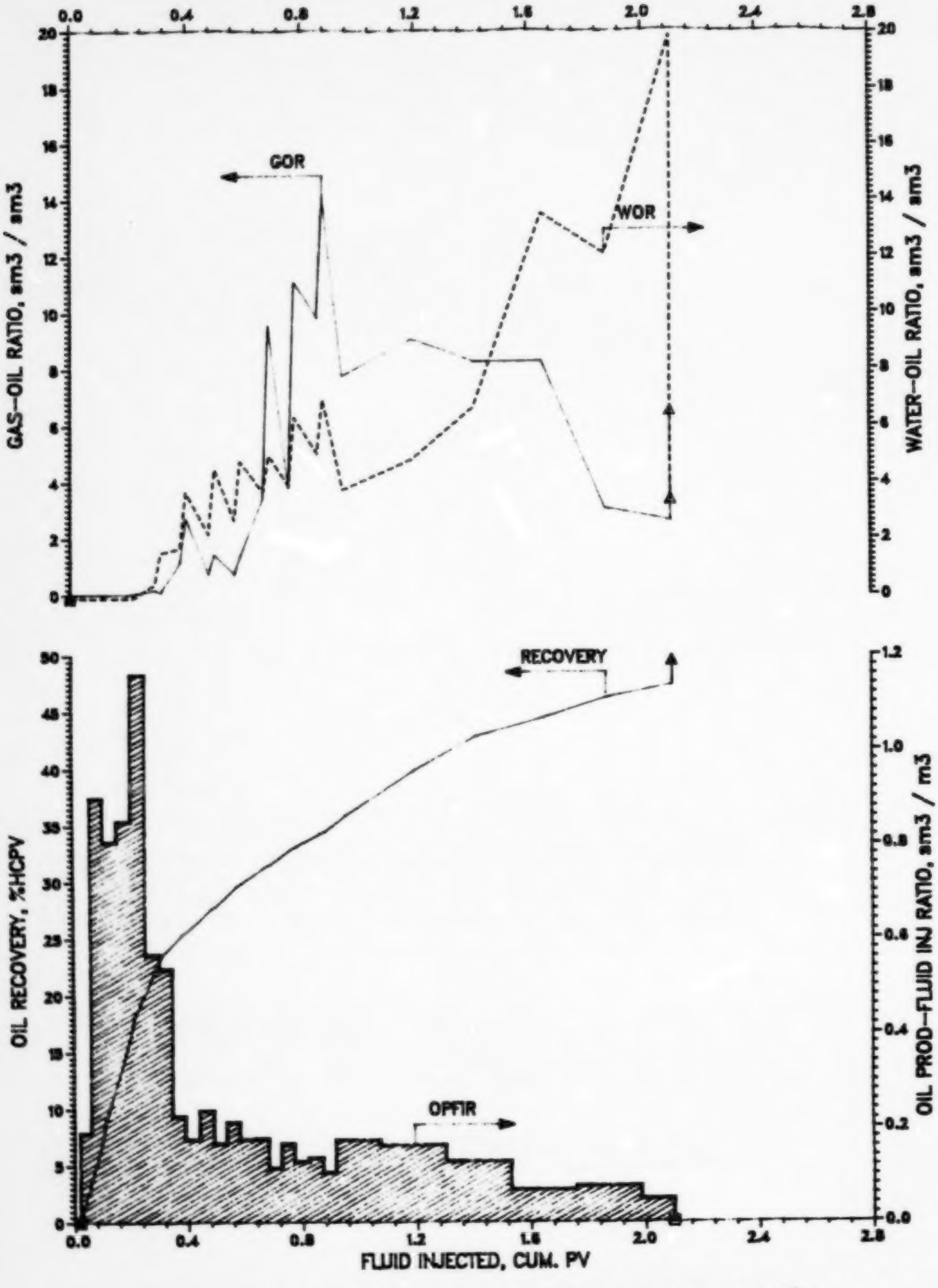
5.3.2 Nitrogen-Carbon Dioxide Experiments

In this and the subsequent sections the experimental results obtained in the present study will be analyzed.

Linear Model Experiments

5.3.2.1. Use of Nitrogen-Carbon Dioxide Mixtures in The Immiscible WAG Displacement

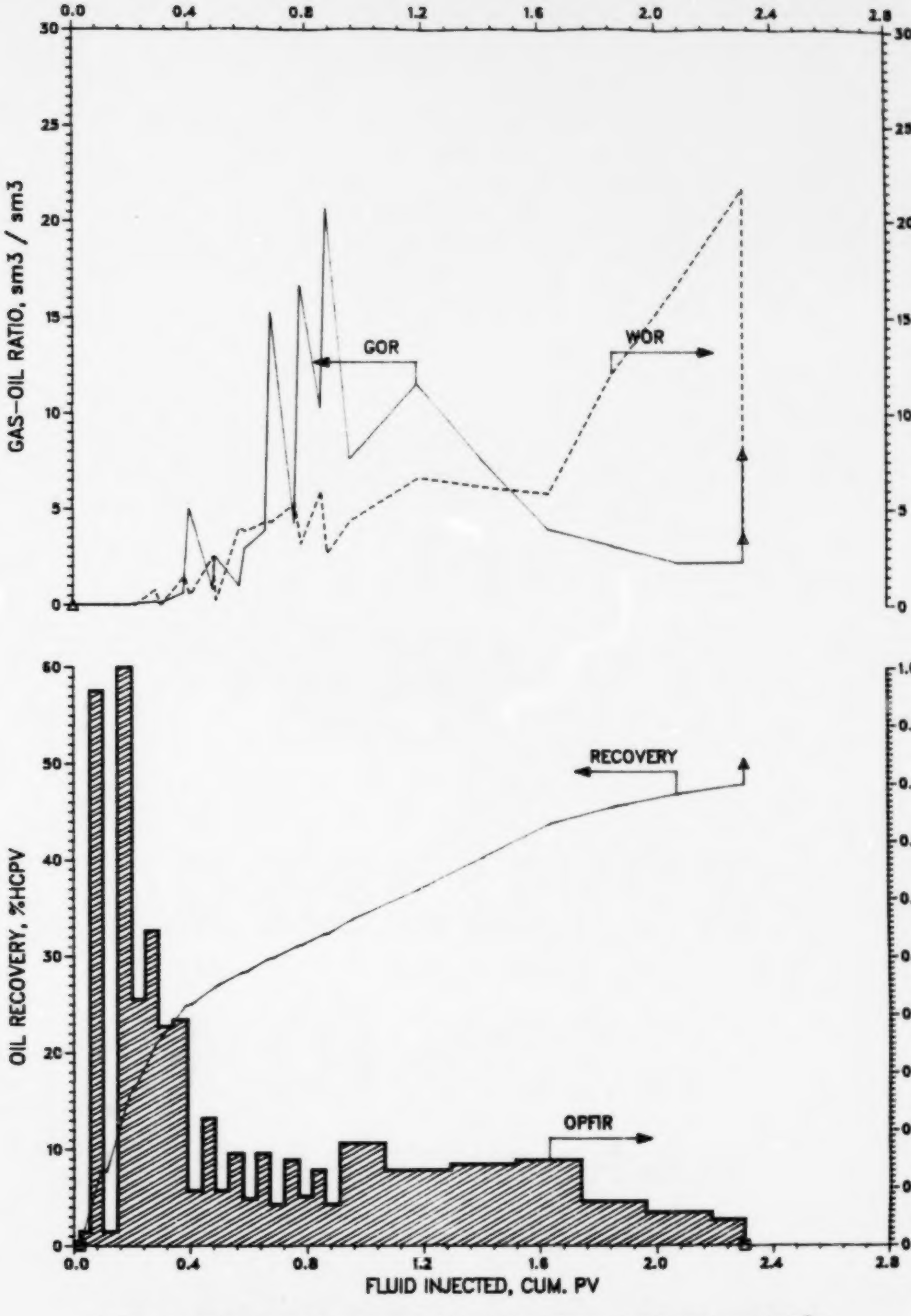
Six linear model runs, 1DT1 to 1DT6, were performed to determine the sensitivity of oil recovery to the use of nitrogen-carbon dioxide gas mixtures. The nitrogen concentrations of the mixtures used in the six runs were 4.98, 9.99, 15.0, 20.0, 25.0, and 30.0 mole%, respectively. In all six runs, a total nitrogen-carbon dioxide gas slug size of 20% HCPV at 1.0 MPa was employed in the 4:1 WAG mode with ten equal slugs. Tables A1 to A6 (Appendix A) summarize the results of the six runs. Figures 5.21 to 5.26 depict the respective producing GOR's, WOR's, and production histories. These figures are arranged in the order of increasing nitrogen concentration in the mixtures. Figure 5.27 shows the producing GOR's and production history of Run LC42[11], which utilized pure



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1058.0 mPa.s
ϕ = 35.73 %, k = 11.310 darcies, S_o = 94.98 %, S_{wc} = 5.02 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.092 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
Nitrogen Concentration in Mixture = 4.98%

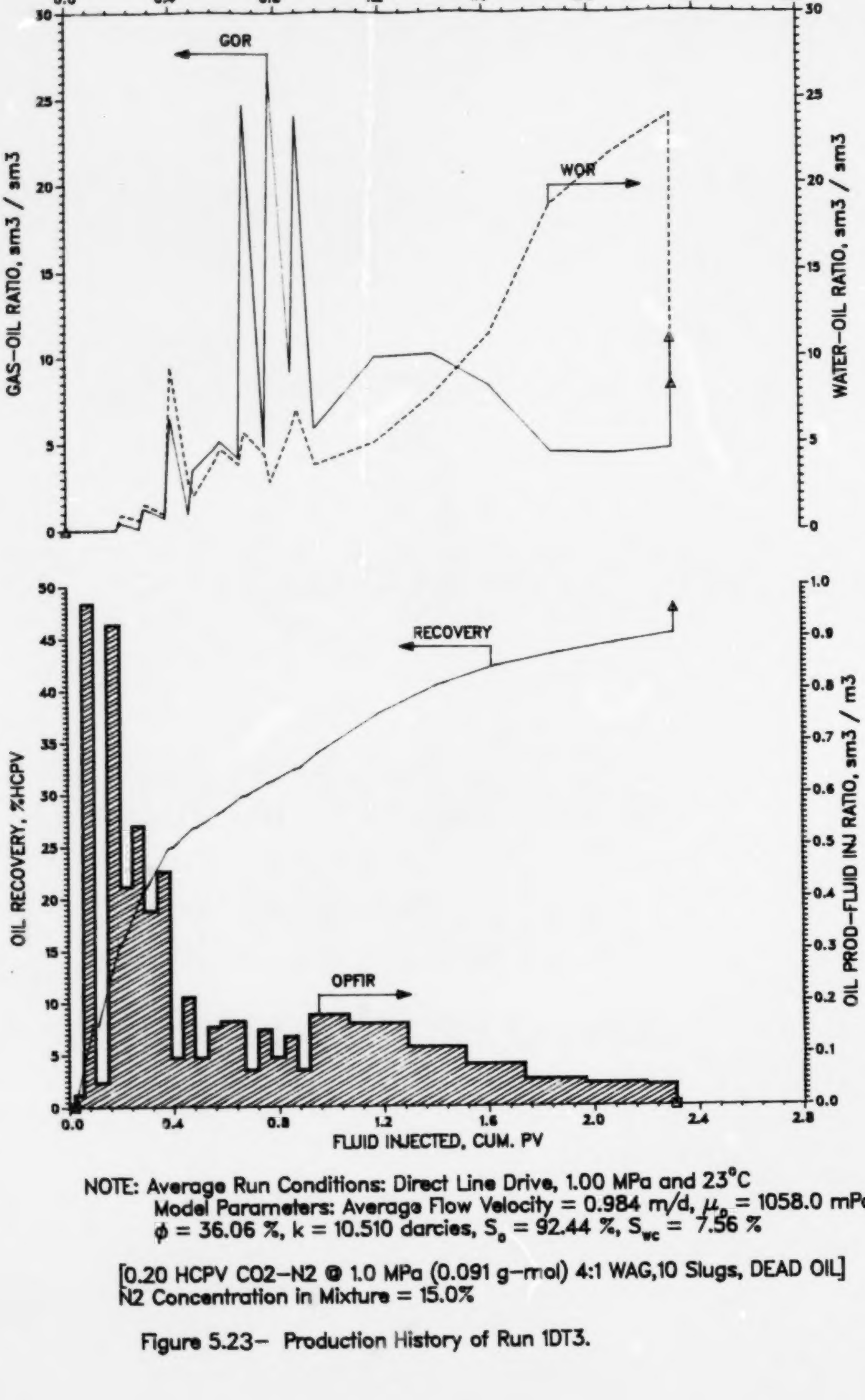
Figure 5.21 – Production History of Run 1DT1.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1058.0 mPa.s
ϕ = 35.82 %, k = 10.700 darcies, S_o = 94.86 %, S_{wc} = 5.14 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.091 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 9.99%

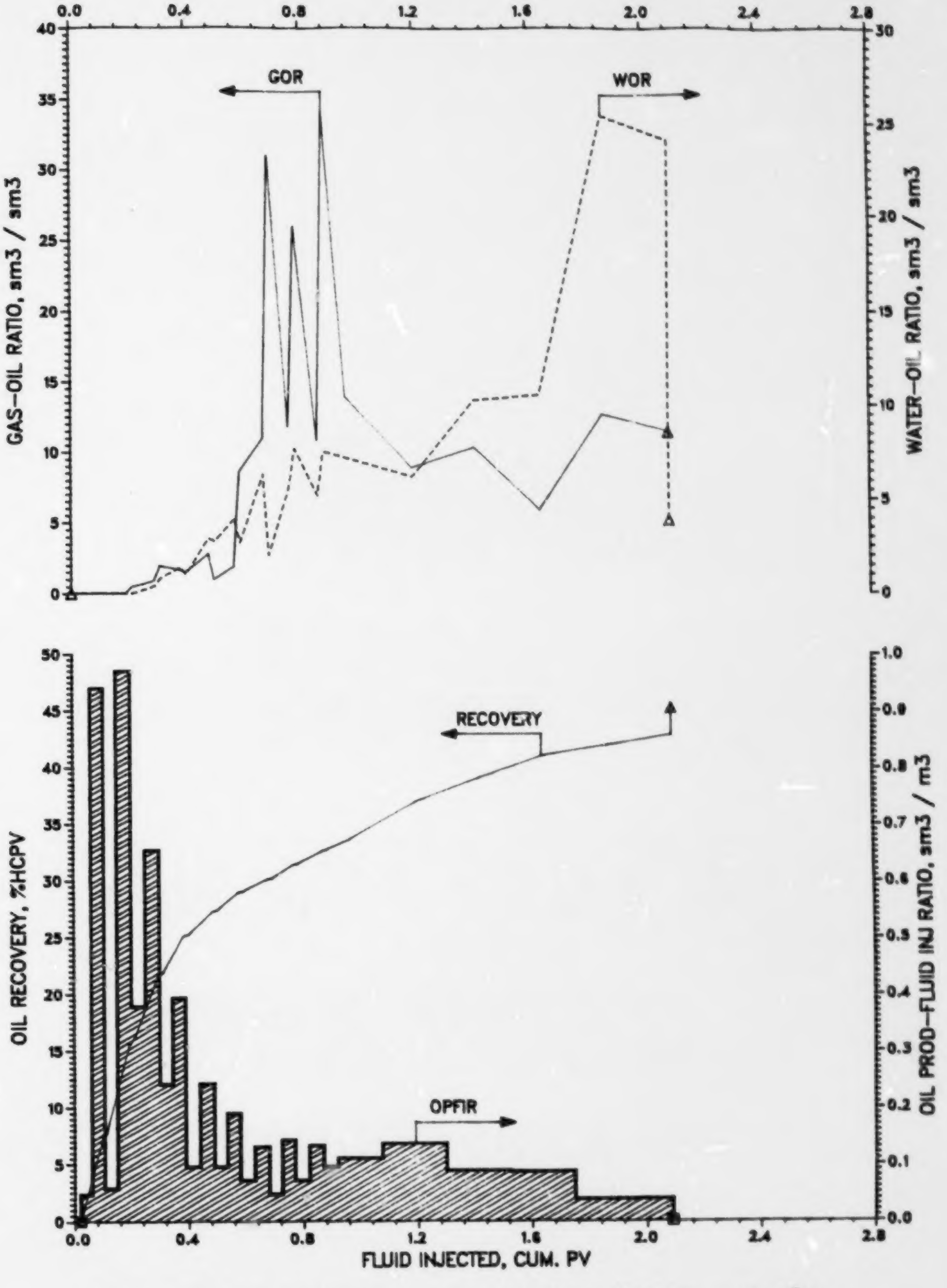
Figure 5.22 – Production History of Run 1DT2.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1058.0 mPa.s
ϕ = 36.06 %, k = 10.510 darcies, S_o = 92.44 %, S_{wc} = 7.56 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.091 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.0%

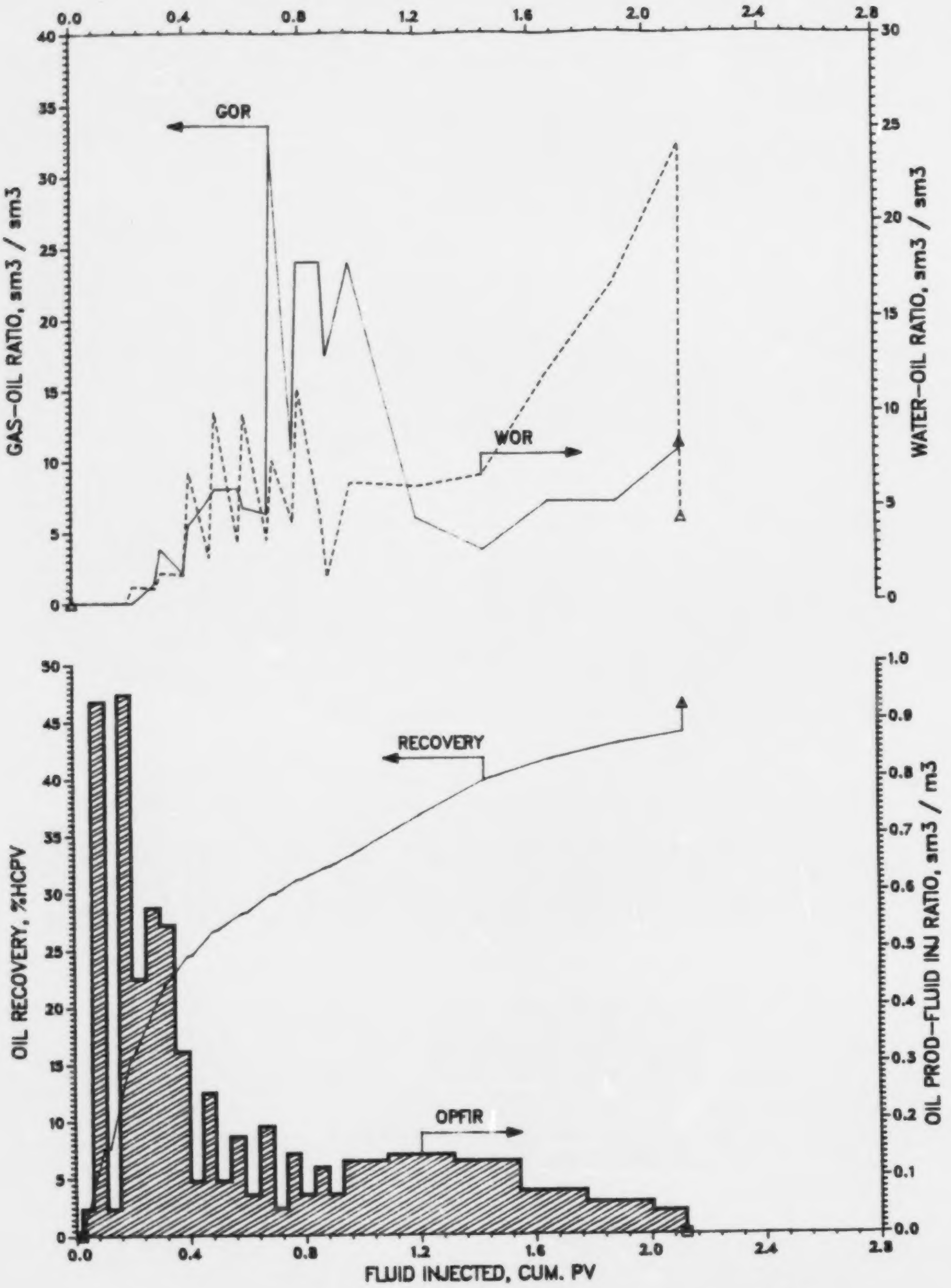
Figure 5.23– Production History of Run 1DT3.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1058.0 mPa.s
ϕ = 35.59 %, k = 10.770 darcies, S_o = 95.53 %, S_{wc} = 4.47 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.090 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 20.0%

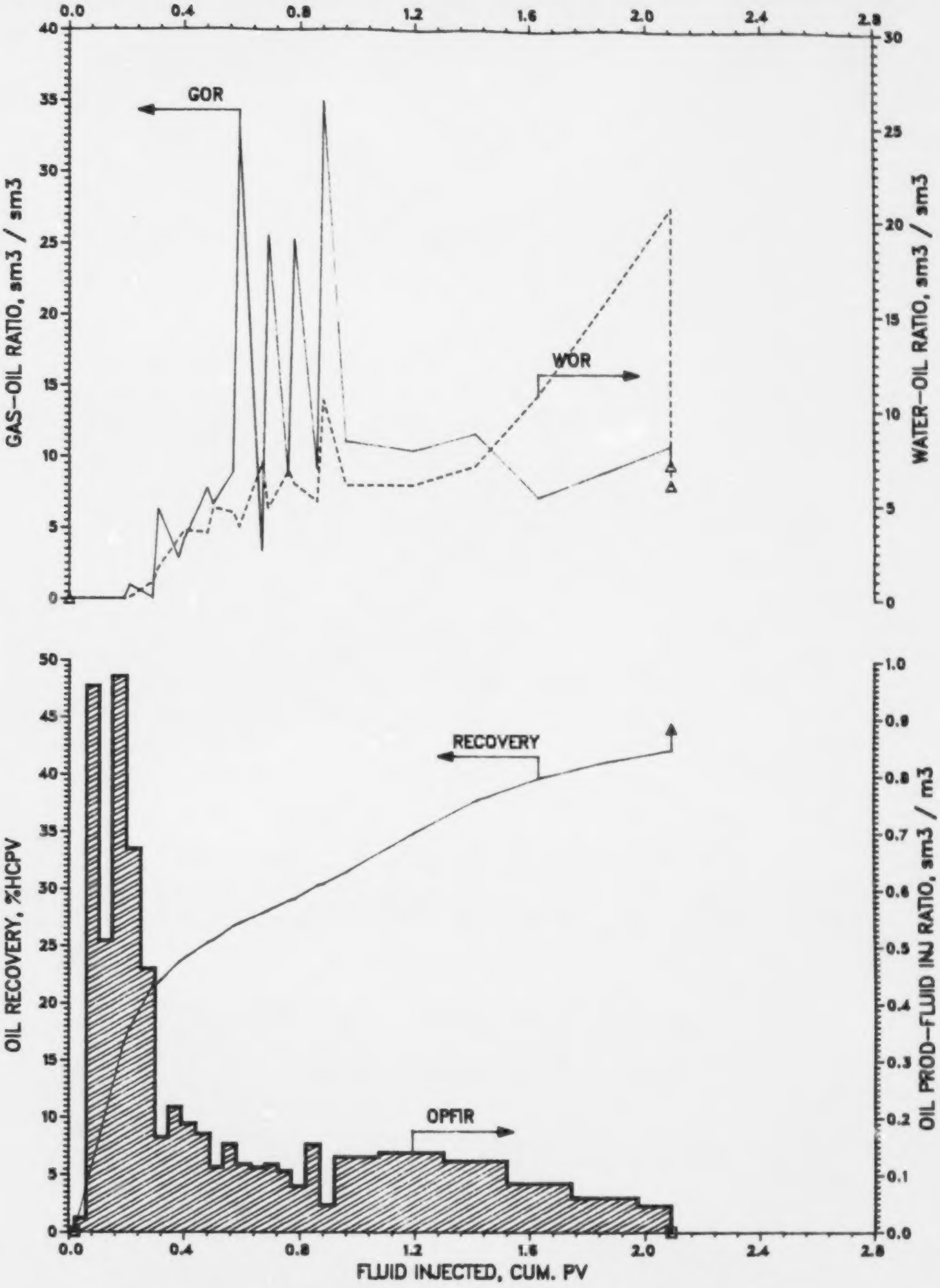
Figure 5.24 – Production History of Run 1DT4.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1058.0 mPa.s
ϕ = 35.16 %, k = 10.630 darcies, S_o = 95.28 %, S_{wc} = 4.47 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.090 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 25.0%

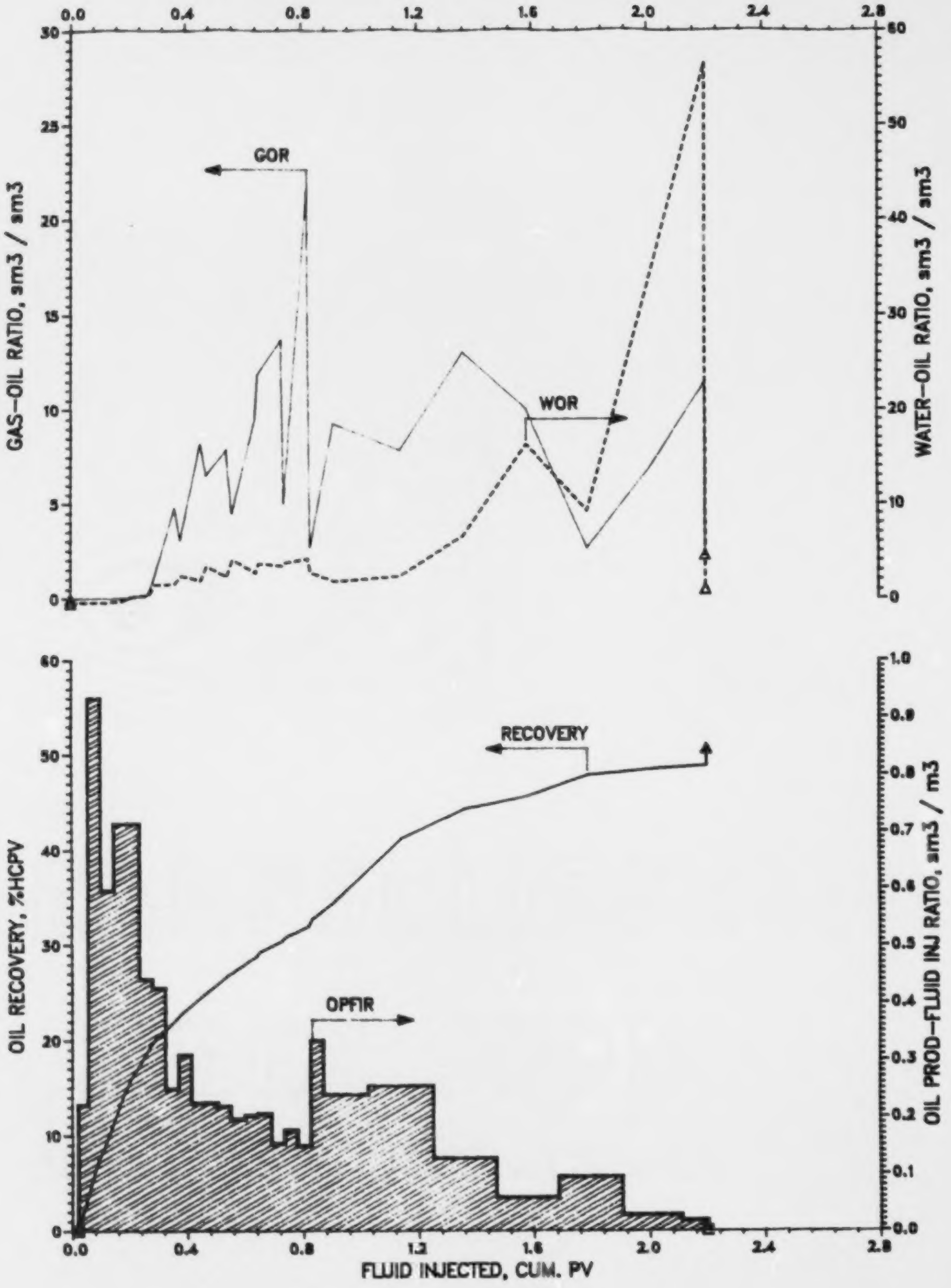
Figure 5.25 – Production History of Run 1DT5.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1058.0 mPa.s
ϕ = 35.70 %, k = 10.730 darcies, S_o = 95.54 %, S_{wc} = 4.46 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.090 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 30.0%

Figure 5.26 – Production History of Run 1DT6.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1046.0 mPa.s
ϕ = 36.10 %, k = 10.990 darcies, S_o = 90.22 %, S_{wc} = 9.78 %

[0.20 HCPV CO2 @ 1.0 MPa (0.089 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]

Figure 5.27 – Production History of Run LC42, After Prosper [Ref. 11].

carbon dioxide. Figure 5.28 provides a comparison of the GOR's for Runs 1DT2, 1DT4, 1DT6, and LC42[11].

Figures 5.21 to 5.27 reveal that the producing GOR increased with increasing nitrogen concentration in the mixture. The comparison in Figure 5.28 shows this more clearly. Nitrogen, being non-condensible, remained as a free gas phase, consequently increasing the relative permeability of the gas phase and increasing the resistance to the diffusion of carbon dioxide into oil. Further evidence of the increased relative permeability to gas due to nitrogen is offered in Figure 5.29, based on Zhu's data[8]. In this figure, the producing GOR for Run 9Z[8] conducted with continuous injection of nitrogen is compared with that of Run 10Z[8] conducted with continuous injection of carbon dioxide. The two curves show that a much larger volume of nitrogen than carbon dioxide was produced and that nitrogen was immediately produced upon injection. This establishes that nitrogen has a much higher relative permeability and mobility than carbon dioxide. Furthermore, recent work by Dria et al.[76] also supports this. Therefore, when nitrogen mixes with carbon dioxide, the resulting nitrogen-carbon dioxide mixture will have a higher relative permeability than pure carbon dioxide. As a result of this, the relative permeability curve of the gas phase is shifted to the left and carbon dioxide-nitrogen easily travels through oil and causes the production of large gas volumes. This is what happened in Runs 1DT1 to 1DT6, where the gas phase relative permeability increased due to increasing nitrogen contents, and as a result a larger volume of gas was produced when the nitrogen content in carbon dioxide increased (Figure 5.28).

The presence of nitrogen in carbon dioxide also had an adverse effect on oil recovery. The total recoveries noted for Runs 1DT1 to 1DT6 were 49.8, 48.7, 47.6, 45.3, 45.0, and 44.3%, respectively for 4.98, 9.99, 15.0, 20.0, 25.0, and 30.0 mole% nitrogen, respectively; while a total recovery of 51.1% was recorded in Run LC42[11] utilizing pure carbon dioxide. Figure 5.30 compares the production histories of Runs 1DT2, 1DT4, 1DT6, and LC42[11]. As shown, for any volume of fluid injected, the recovery was lower for carbon dioxide with a higher nitrogen content. This recovery decrease is explained by the reduction in the solubility and diffusivity of carbon dioxide into oil due to the presence of nitrogen, as illustrated in Sections 5.1 and 5.2. As a result, the effective mobility ratio was lower than in the case of pure carbon dioxide.

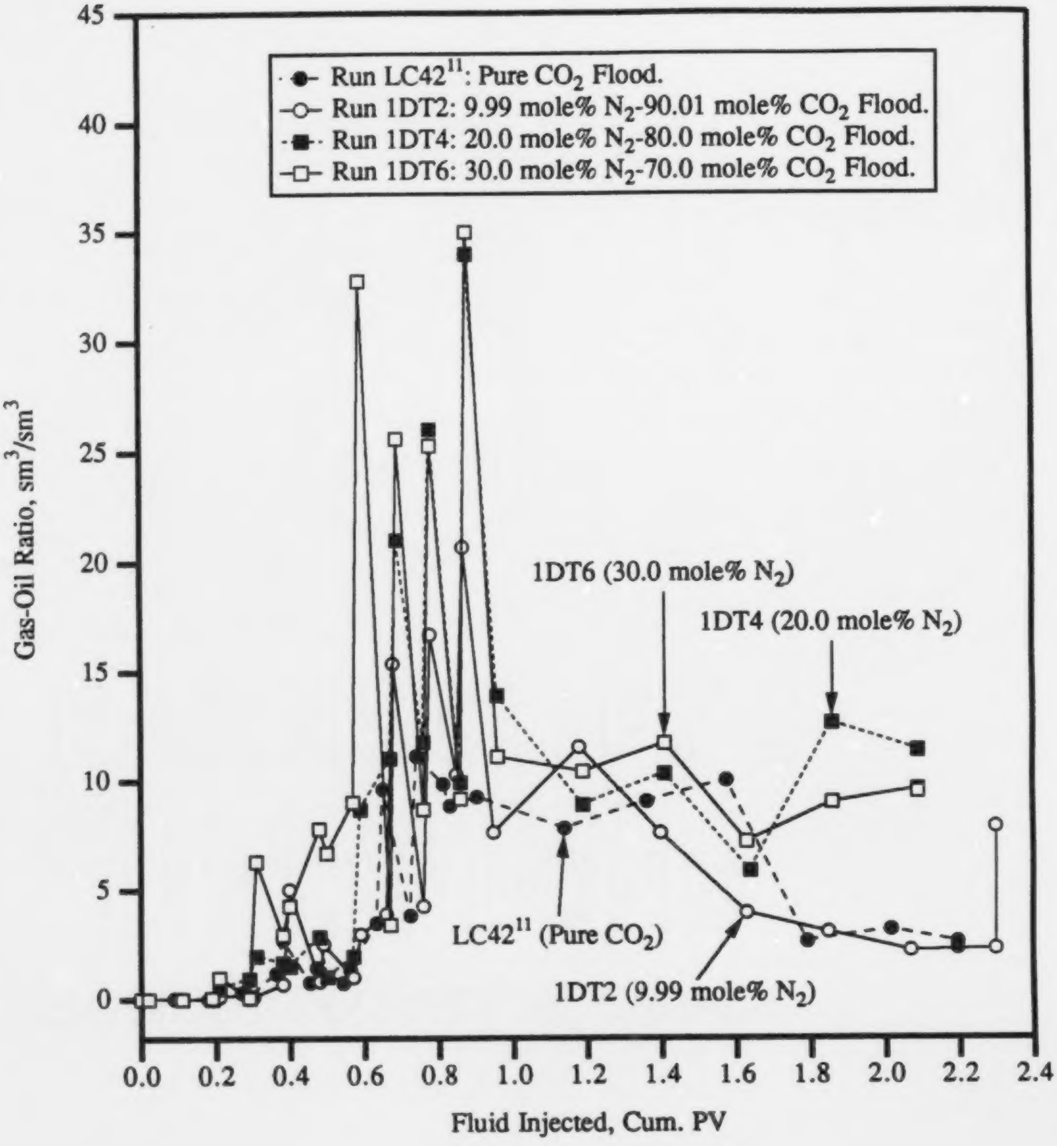


Figure 5.28 - Effect of Nitrogen on Producing GOR's.

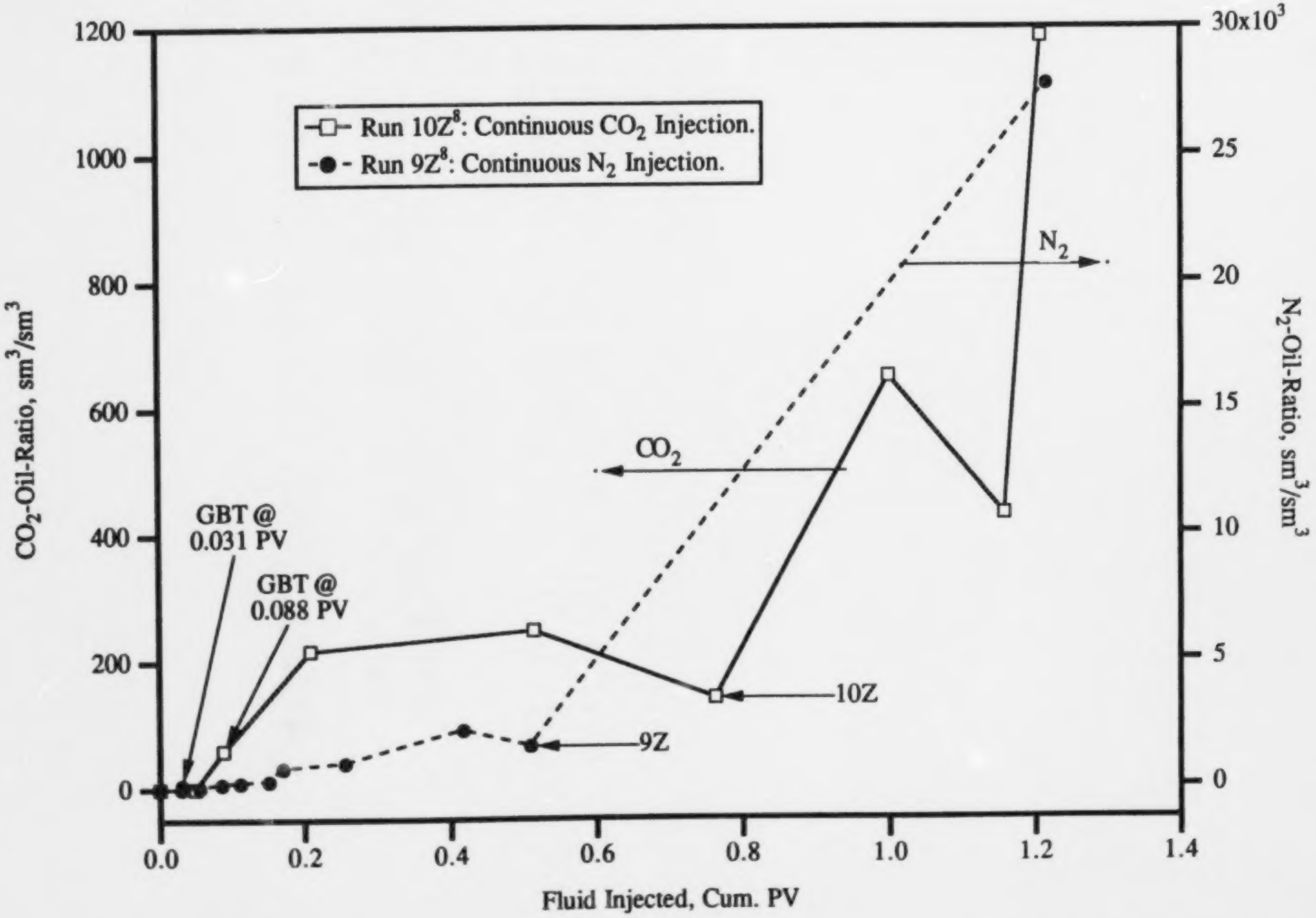


Figure 5.29 - Illustration on Producing Carbon Dioxide and Nitrogen GOR's (Data From Ref. 8).

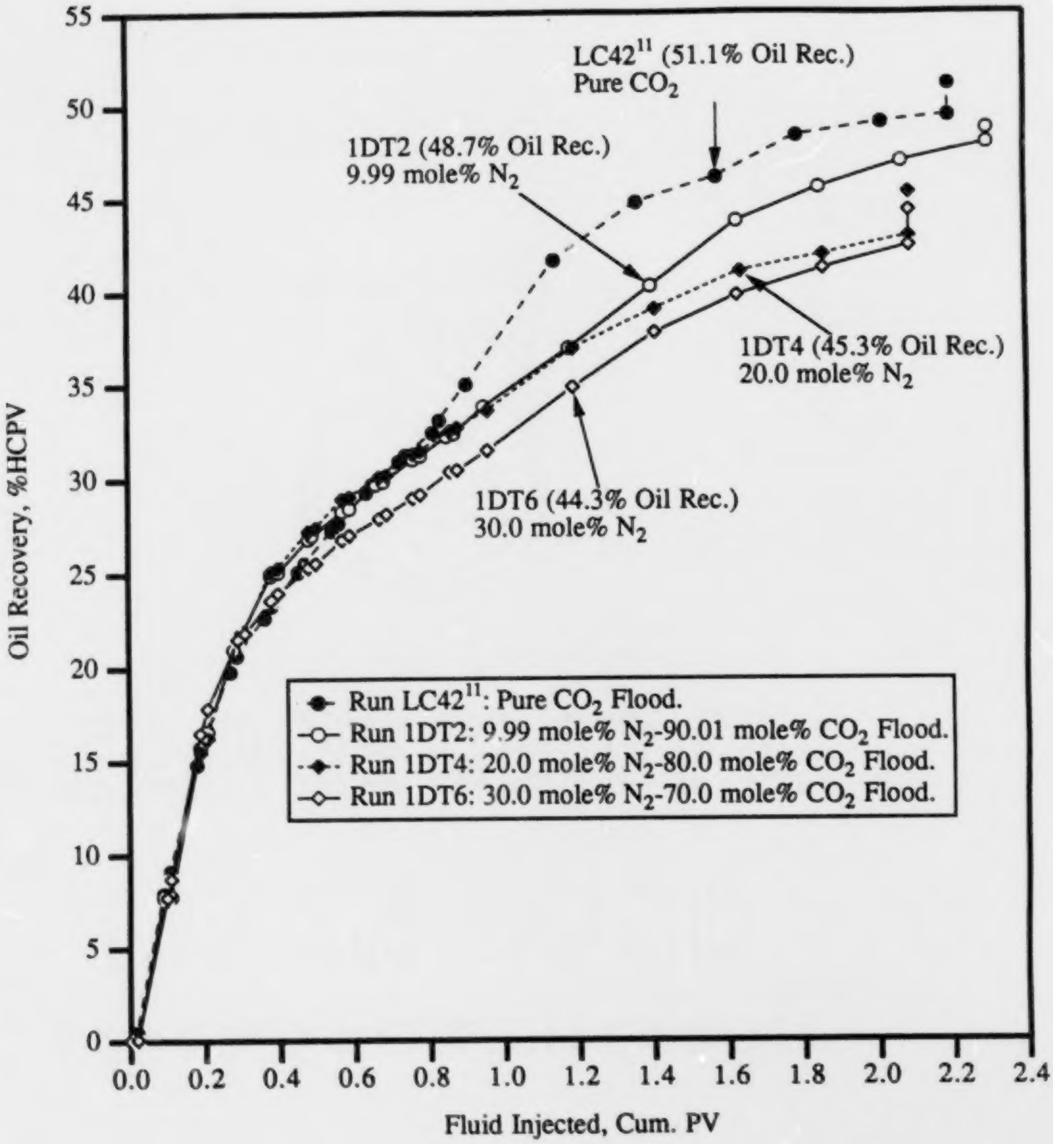


Figure 5.30 - Effect of Nitrogen on Oil Recovery.

5.3.2.2 Effect of Nitrogen on Oil Production Rate

Figure 5.31 shows the effect of nitrogen on the instantaneous oil production rate, which decreased as the concentration of nitrogen in carbon dioxide increased. The average production rate followed the same trend. The overall average oil production rates for Runs 1DT1 to 1DT6 were 0.026, 0.024, 0.024, 0.023, 0.023, and 0.022 cm^3/s, respectively; while it was 0.028 cm^3/s for Run LC42[11]. These values show that, for a 5% increase in the nitrogen content in the carbon dioxide stream, the oil production rate decreased by about 0.001 to 0.002 cm^3/s, or 3.6 to 7.1% (compared to pure carbon dioxide) . This is largely attributed to the decreased liquid phase relative permeability due to the large free gas saturation.

5.3.2.3 Effect of Nitrogen on Carbon Dioxide Gas Production Rate

In contrast to reducing the oil production rate, nitrogen had a tendency to increase the production rate of carbon dioxide, as measured during an experiment. The effect of nitrogen on increasing the carbon dioxide production rate is illustrated in Figure 5.32. The carbon dioxide production rate increased as the nitrogen content of the injected gas increased. The average carbon dioxide production rate increased from 0.092 cm^3/s for pure carbon dioxide to 0.150 cm^3/s for a 30 mole% nitrogen-70 mole% carbon dioxide mixture. The gas rate reached a maximum and then decreases due to continued water injection after the WAG phase. This is expected because the volume of gas injected is limited.

5.3.2.4 Effect of Initial Oil Viscosity

Linear model Runs 1DT1 to 1DT6 were conducted using a 1,058 mPa.s viscosity oil; some of the experiments had been performed in the previous studies[5,8] using oils of higher viscosities, 4,681 mPa.s and 2,107 mPa.s. None was conducted using a lower viscosity oil. In this study many experiments were carried out with a 888.0 mPa.s viscosity oil to examine the effect of a lower viscosity oil on the immiscible WAG process. Seven runs, 1DT7 to 1DT13, were carried out using this 888.0 mPa.s viscosity oil. The volume of gas injected in these runs was kept constant at 20% HCPV at 1.0 MPa and the WAG ratio was 4:1. Also, the nitrogen-carbon dioxide mixtures used contained 0 to 30.0 mole% nitrogen, in increments of 5.0 mole%. Tables A7 to A13 in Appendix A contain the results of these seven runs.

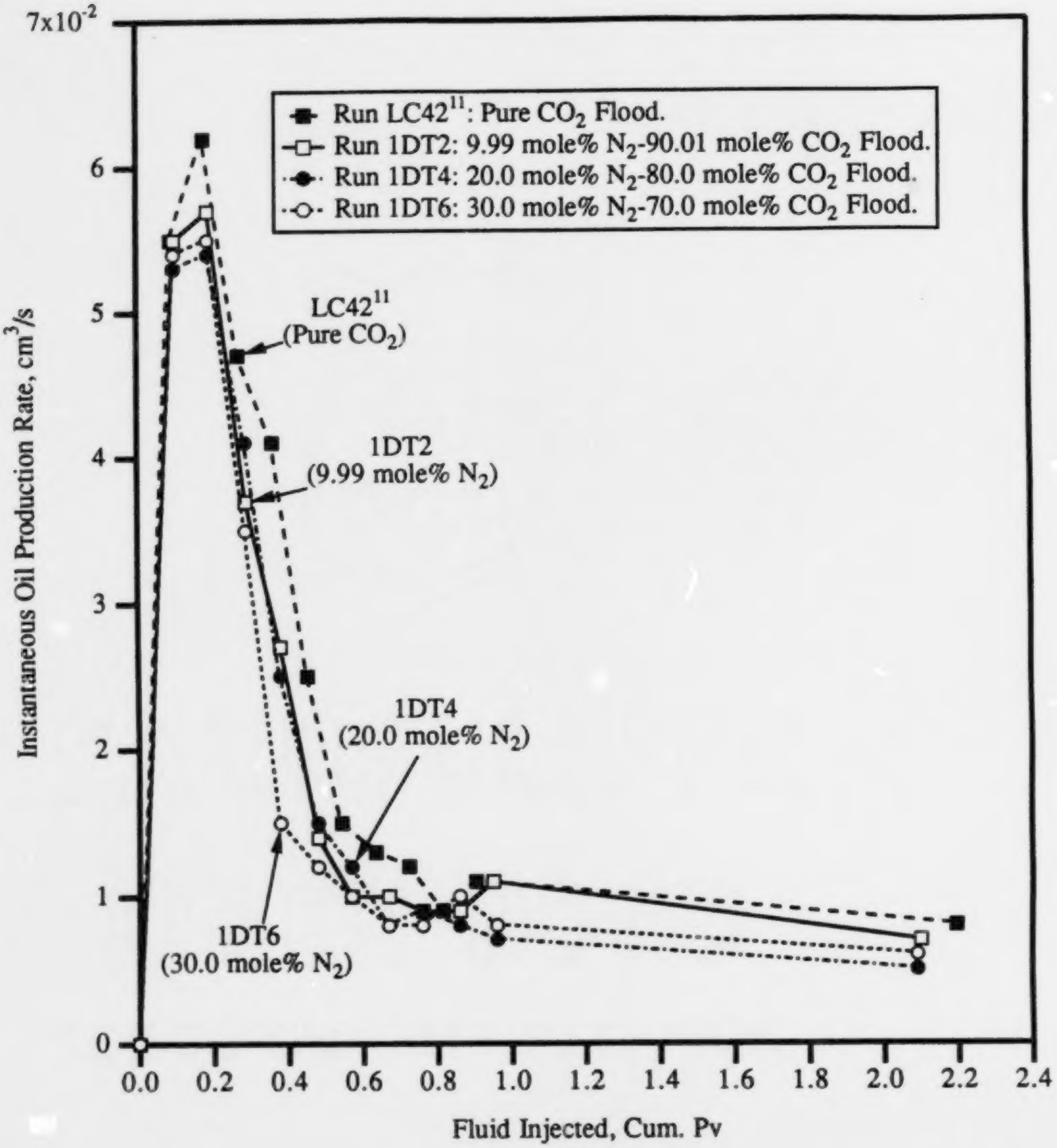


Figure 5.31 - Effect of Nitrogen on Oil Production Rate.

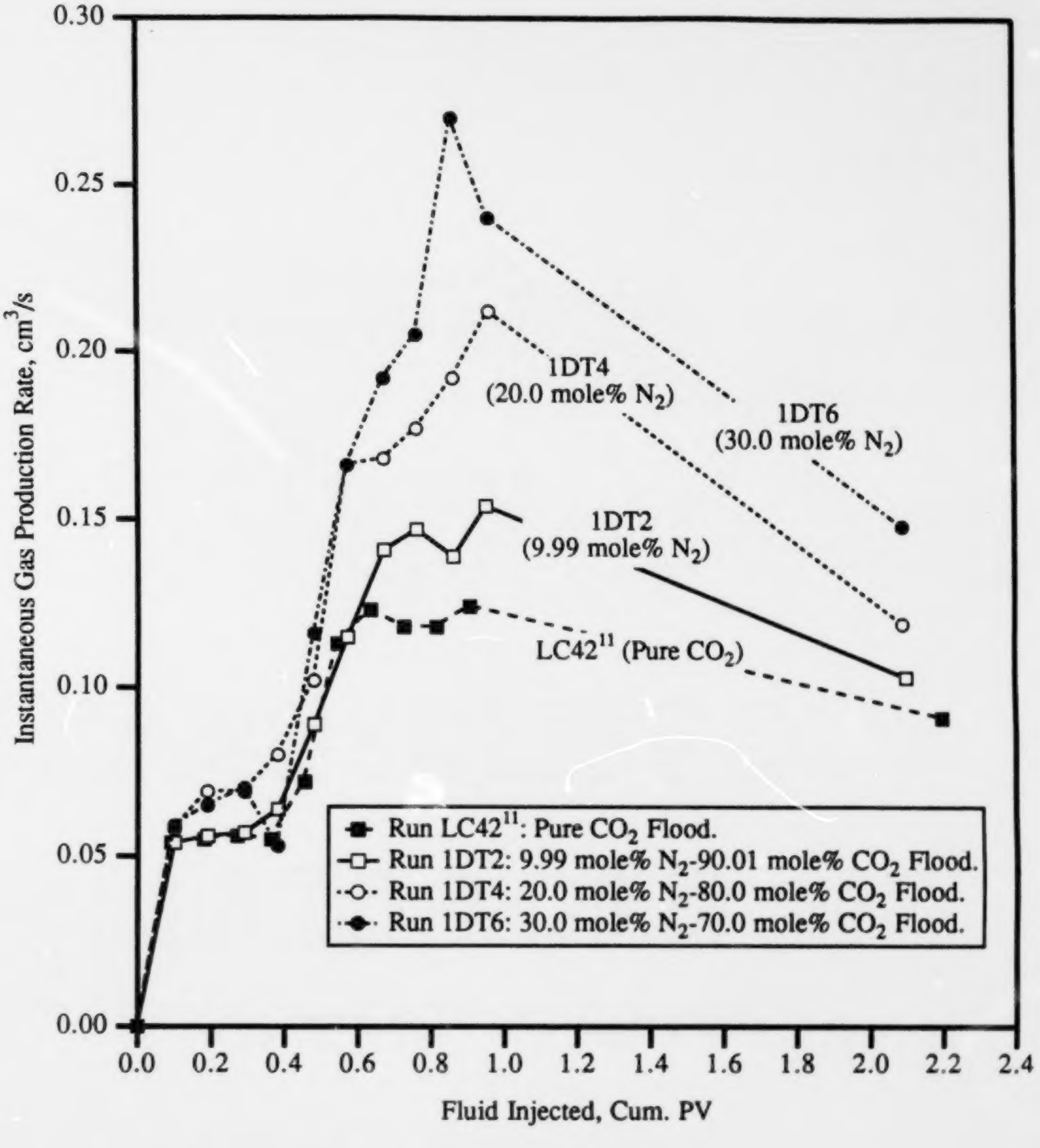


Figure 5.32 - Effect of Nitrogen on Gas Production Rate.

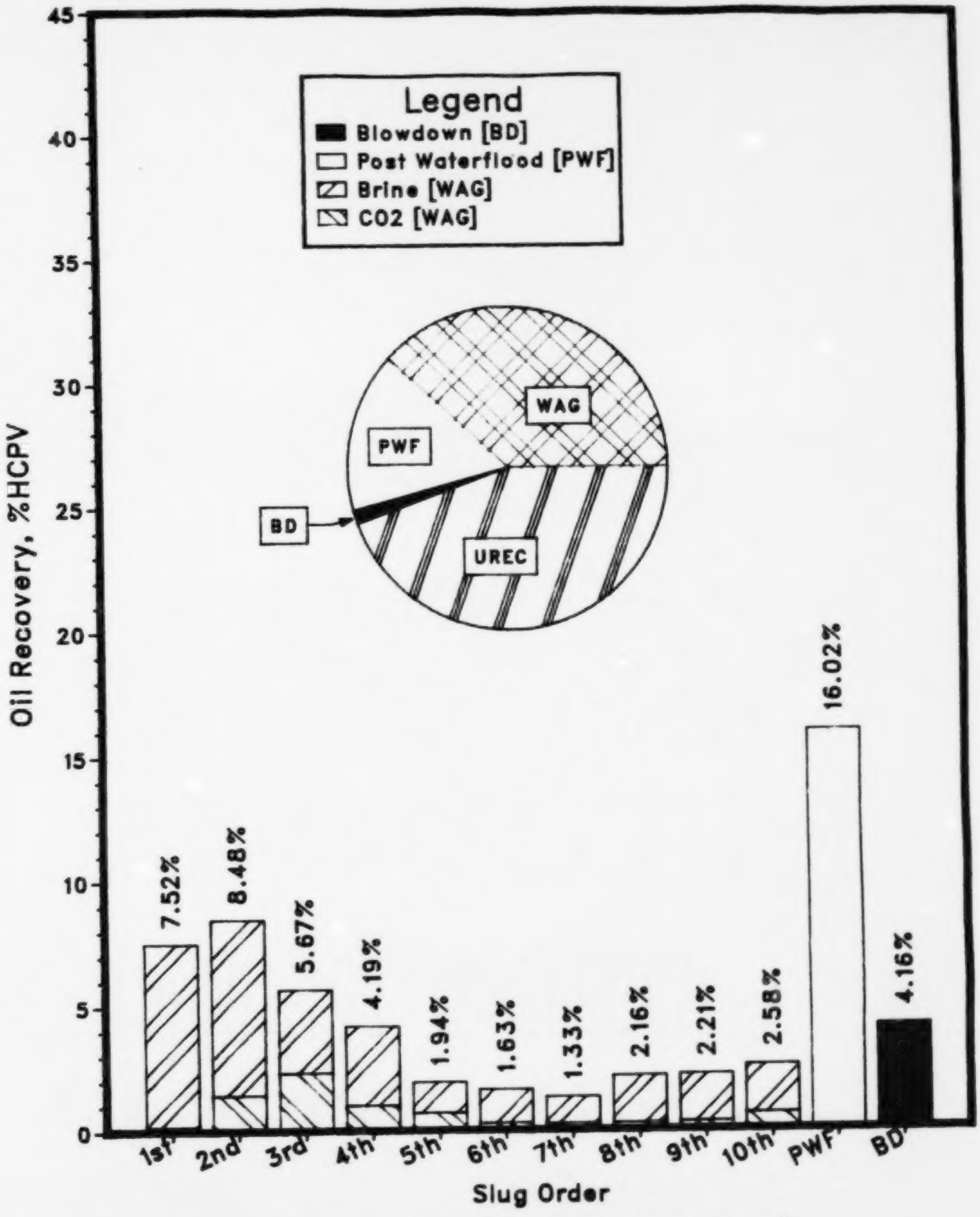
Figures 5.33 to 5.39 show the oil recovery breakdown for each WAG slug for Runs 1DT7 to 1DT13. They are arranged in the order of increasing nitrogen concentration in the mixture. The total recoveries were 57.9, 55.5, 54.6, 54.5, 54.3, 52.5, and 51.4% for Runs 1DT7 to 1DT13, respectively. These values are unexpectedly high for an immiscible WAG process utilizing a nitrogen-carbon dioxide mixture in place of pure carbon dioxide. Also, it is noted that, as in the case of Runs 1DT1 to 1DT6 (1,058 mPa.s oil runs), recovery decreased as the nitrogen concentration increased.

Table 5.5 gives a comparison of the results of Runs 1DT7 to 1DT13 with those of Runs 1DT1 to 1DT6. It is noted that, for all nitrogen-carbon dioxide mixtures used, more oil was recovered in Runs 1DT7 to 1DT13 than in Runs 1DT1 to 1DT6 at each stage of the process. A lower oil viscosity is believed to lead to an increase in recovery since a less viscous oil can be displaced more easily by WAG and post-waterflood than a more viscous oil.

Another explanation for the increased recovery is the increased diffusion. According to Schmidt's correlation[50], the higher the viscosity of the fluid, the lower is the diffusion of carbon dioxide into that fluid. Based upon this, it is expected that the diffusion of nitrogen-carbon dioxide mixture was higher in the 888.0 mPa.s oil than in the 1,058.0 mPa.s oil. As a result, a greater reduction in viscosity can be expected for the 888.0 mPa.s oil, consequently leading to higher recoveries in Runs 1DT7 to 1DT13.

Since more gas diffused into the oil in Runs 1DT7 to 1DT13 due to the lower oil viscosity, a smaller volume of gas remained as free gas phase, compared to Runs 1DT1 to 1DT6. This helped to reduce the fingering of gas through oil, thus retarding gas breakthrough. As demonstrated in Table 5.5, gas breakthrough (GBT) occurred later in Runs 1DT7 to 1DT13 than in Runs LC42[11] and 1DT1 to 1DT6. As a result, oil recoveries at gas breakthrough were higher in Runs 1DT7 to 1DT13 than in the other runs.

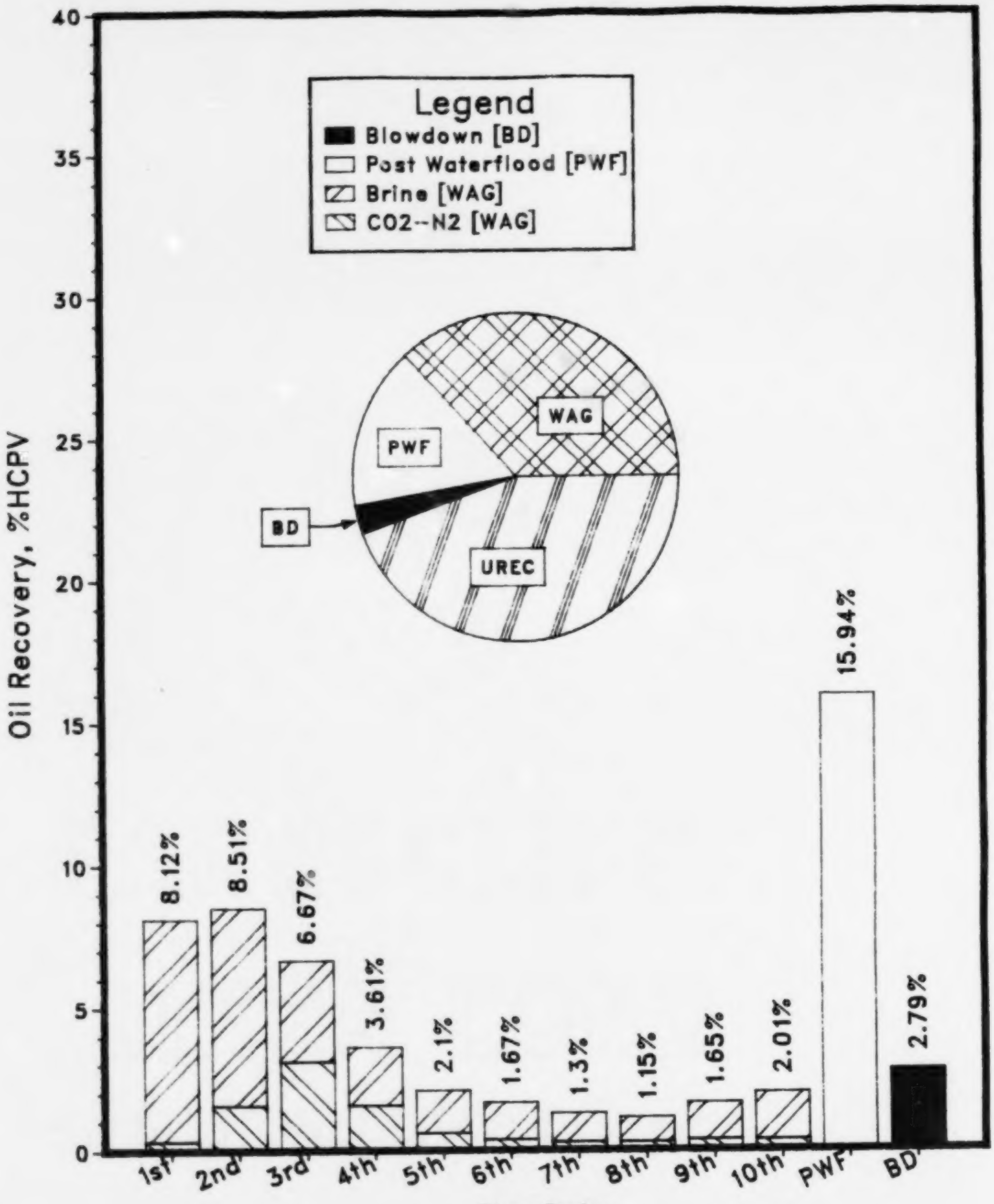
Furthermore, as a result of higher carbon dioxide diffusivity into the 888.0 mPa.s oil than into the 1058.0 mPa.s oil, the oil-water interfacial tension was lower, which increased the possibility of formation of water-in-oil emulsions which helped to stabilize the post-waterflood, delaying water breakthrough (WBT). Table 5.5 compares the WBT's for the two different viscosity oils. Water breakthrough was later in Runs 1DT7 to 1DT13 than in Runs LC42[11] and 1DT1 to 1DT6. In addition, due a greater viscosity reduction, a lower mobility ratio was realized and thus a better sweep efficiency, as well as a more



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.83 %, k = 11.040 darcies, S_o = 94.98 %, S_{wc} = 5.02 %

[0.20 HCPV CO2 @ 1.0 MPa (0.092 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]
Total Oil Recovery = 57.9 %HCPV

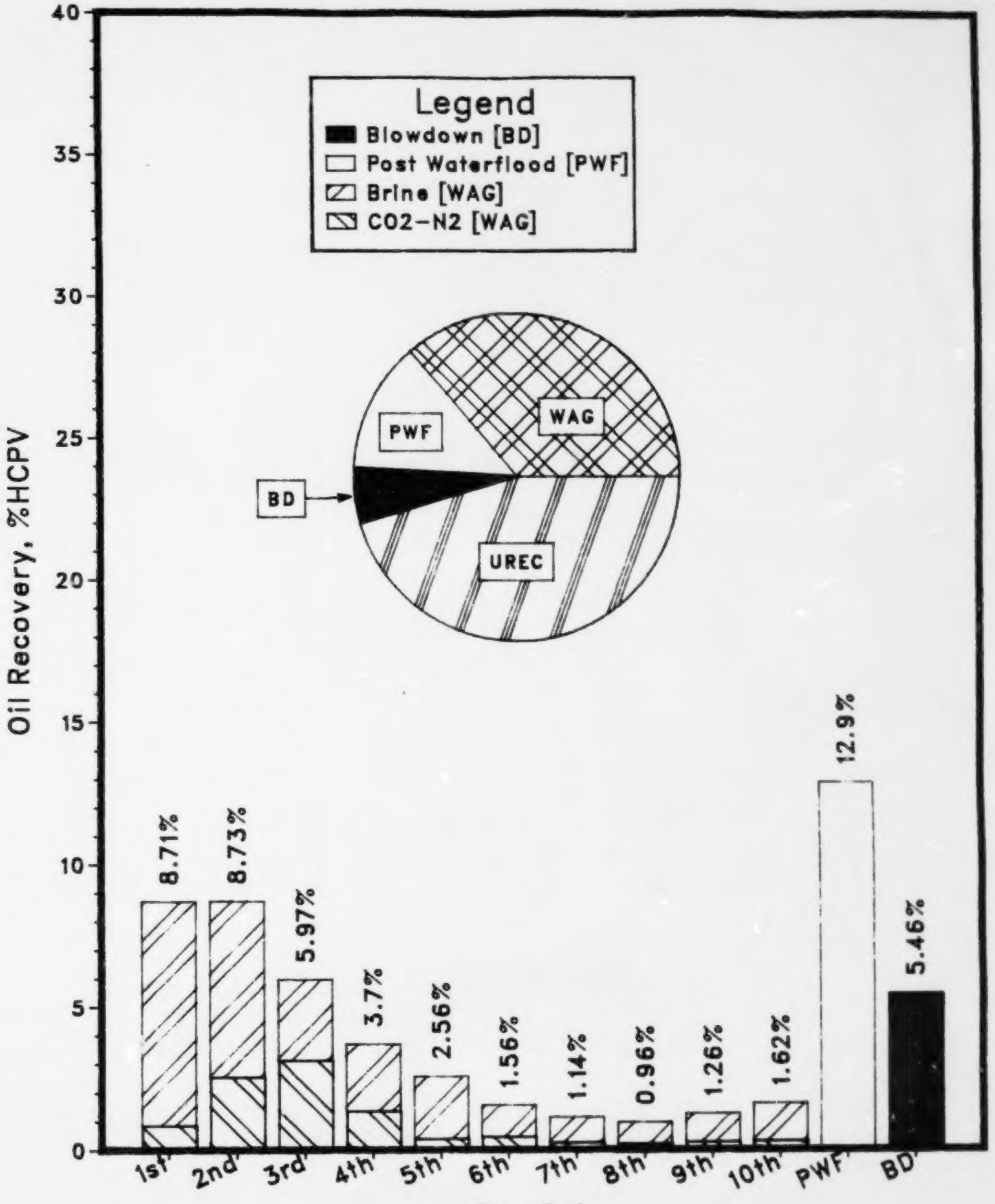
Figure 5.33 – Oil Recovery Distribution of Run 1DT7.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 36.43 %, k = 11.180 darcies, S_o = 94.99 %, S_{wc} = 5.01 %

[0.20 HCPV CO2–N2 @ 1.00 MPa (0.092 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 4.98%
Total Oil Recovery = 55.5 %HCPV

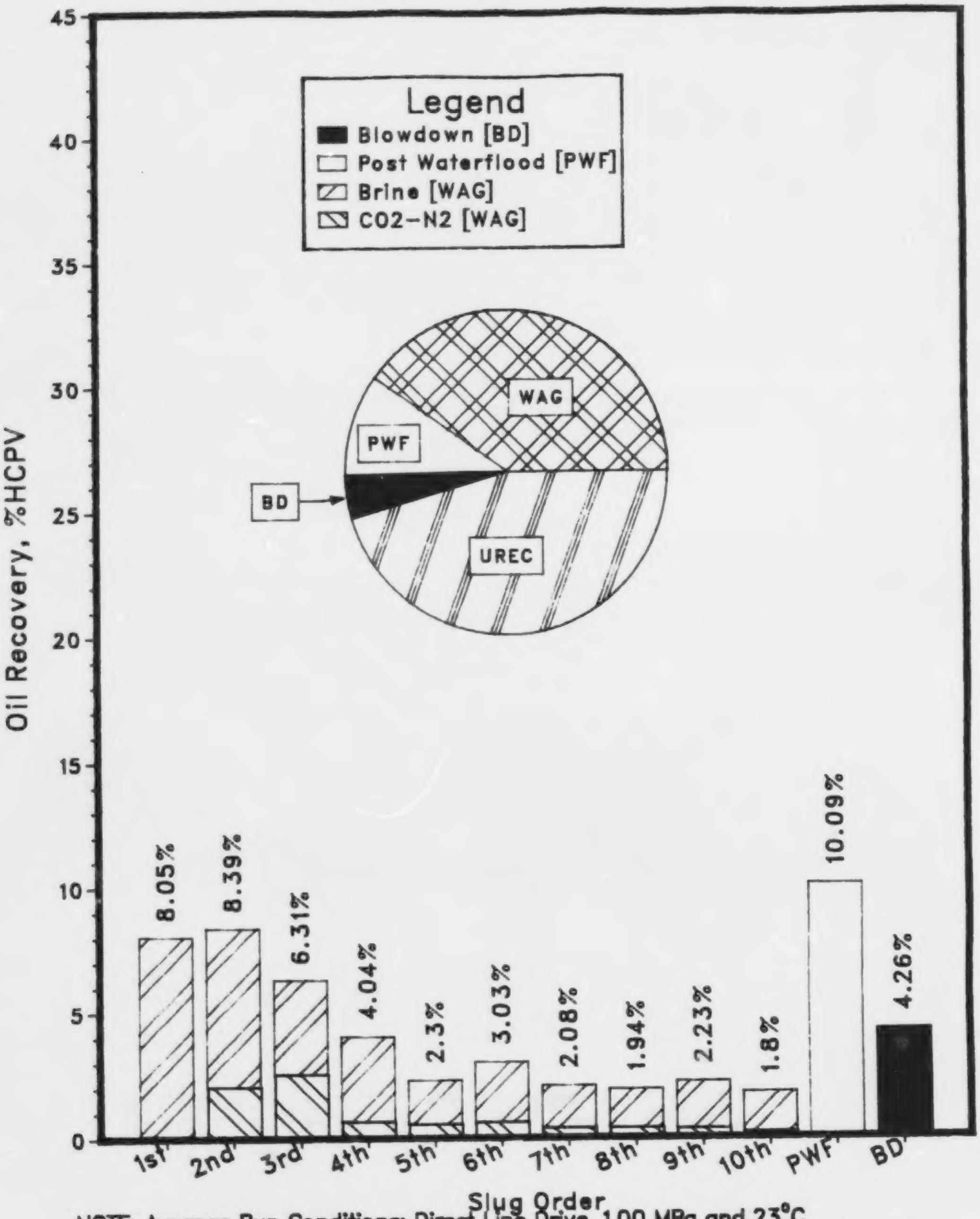
Figure 5.34 – Oil Recovery Distribution of Run 1DT8.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 36.06 %, k = 11.140 darcies, S_o = 94.71 %, S_{wc} = 5.29 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.091 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 9.99%.
Total Oil Recovery = 54.6 %HCPV

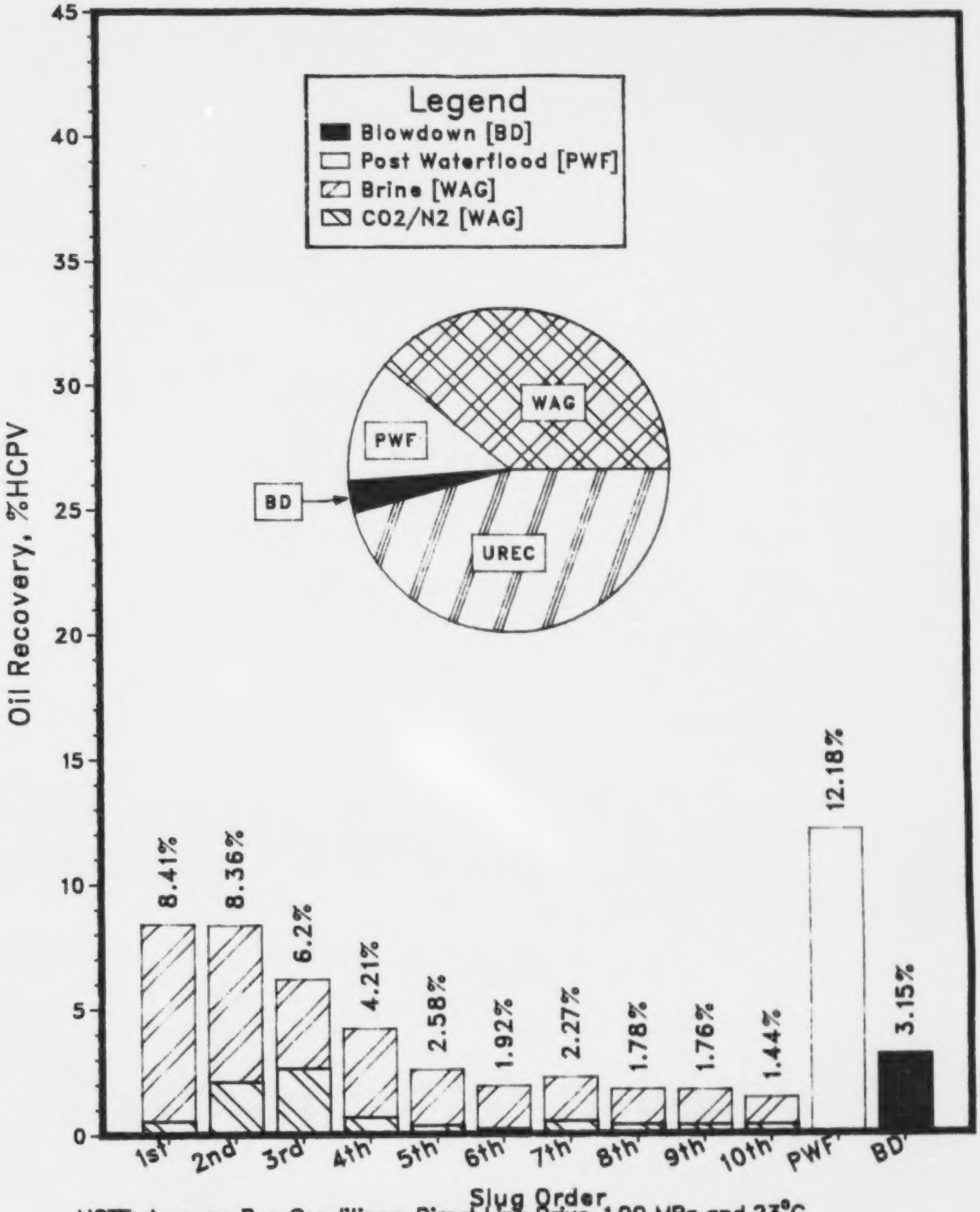
Figure 5.35 – Oil Recovery Distribution of Run 1DT9.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.73 %, k = 11.530 darcies, S_o = 95.05 %, S_{wc} = 4.95 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.090 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.00%
Total Oil Recovery = 54.5 %HCPV

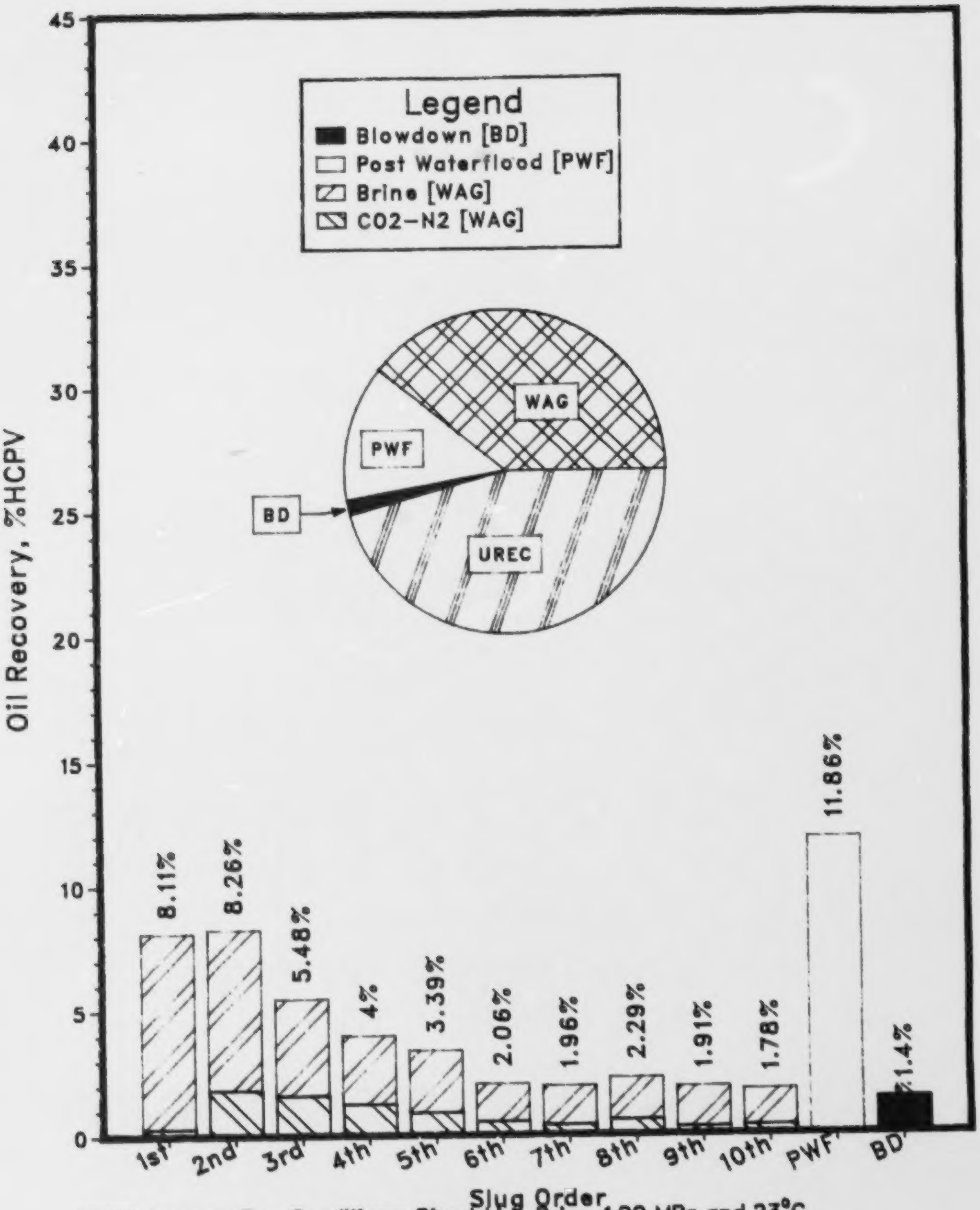
Figure 5.36 – Oil Recovery Distribution of Run 1DT10.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.77 %, k = 11.890 darcies, S_o = 94.12 %, S_{wc} = 5.88 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.089 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 20.00%
Total Oil Recovery = 54.3 %HCPV

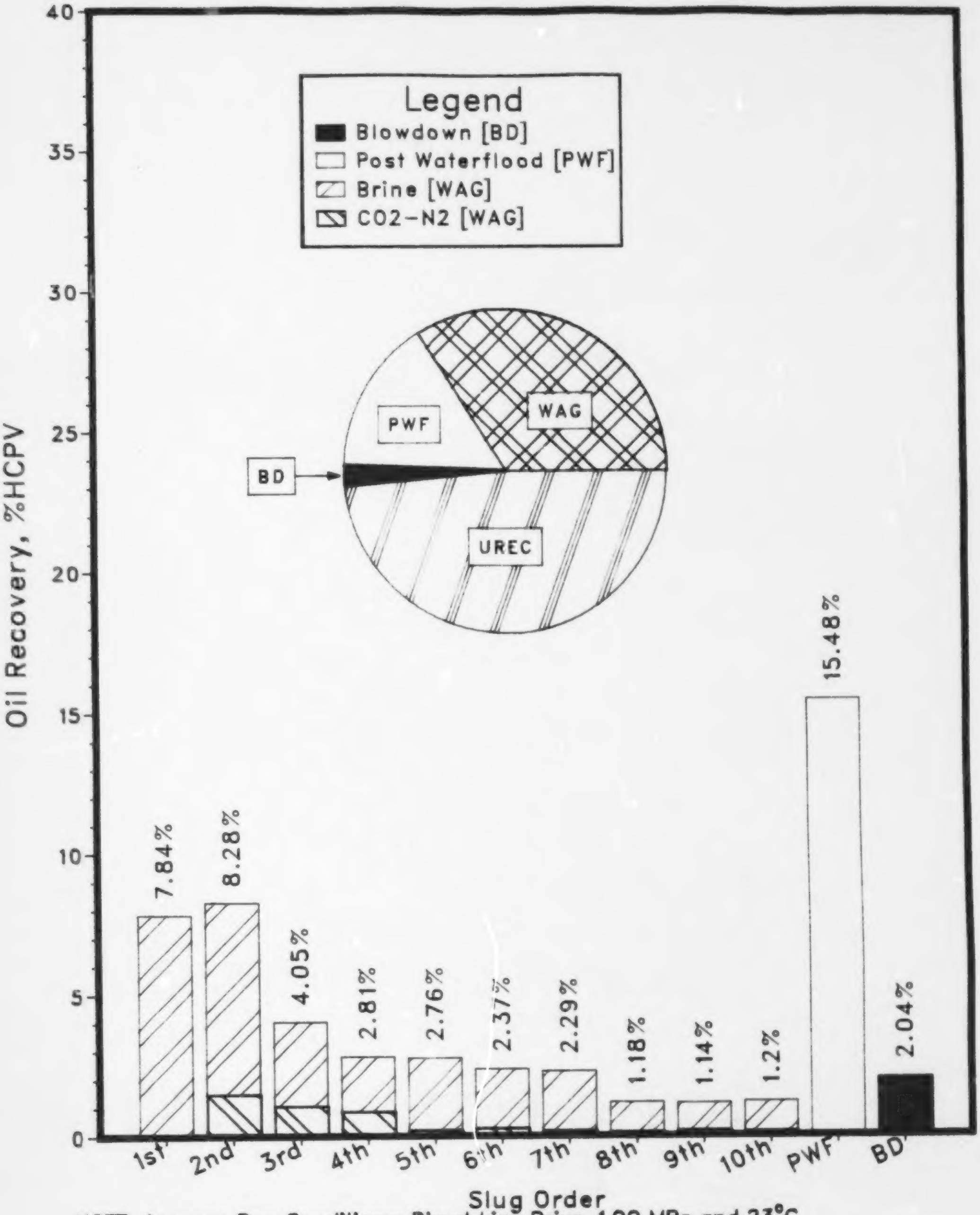
Figure 5.37 – Oil Recovery Distribution of Run 1DT11.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.77 %, k = 11.430 darcies, S_o = 95.77 %, S_{wc} = 4.23 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.091 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 25.00%
Total Oil Recovery = 52.5 %HCPV

Figure 5.38 – Oil Recovery Distribution of Run 1DT12.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.22 %, k = 11.090 darcies, S_o = 96.16 %, S_{wc} = 3.84 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.089 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 30.00%
Total Oil Recovery = 51.4 %HCPV

Figure 5.39 – Oil Recovery Distribution of Run 1DT13.

stable displacement front, was obtained. This also contributed to higher recoveries in the less viscous oil runs.

Table 5.5 - Comparison of Low Viscosity Oil Runs With High Viscosity Oil Runs.

Run No.	N_2 Conc. in CO_2 (mole%)	Oil Viscosity (mPa.s)	WAG Rec. (%)	PWF Rec. (%)	BD Rec. (%)	Total Rec.	GBT (PV) (%)	WBT (PV)	Rec. @ GBT (%)
LC42[11]	0.0	1046.0	35.0	14.4	1.7	51.1	0.38	0.29	22.7
1DT1	4.98	1058.0	36.2	11.6	1.3	49.3	0.38	0.29	25.7
1DT2	9.99	1058.0	33.8	14.1	0.8	48.7	0.28	0.28	21.0
1DT3	15.0	1058.0	33.7	11.5	2.4	47.6	0.21	0.21	16.1
1DT4	20.0	1058.0	33.6	9.3	2.4	45.3	0.21	0.21	16.2
1DT5	25.0	1058.0	33.3	9.2	2.5	45.0	0.21	0.21	16.2
1DT6	30.0	1058.0	31.5	10.9	1.9	44.3	0.21	0.21	17.8
1DT7	0.0	888.0	38.1	16.1	3.1	57.9	0.38	0.30	25.9
1DT8	4.98	888.0	36.8	15.9	2.8	55.5	0.38	0.30	26.9
1DT9	9.99	888.0	36.2	12.9	5.5	54.6	0.3	0.30	24.8
1DT10	15.0	888.0	40.2	10.1	4.3	54.5	0.29	0.29	22.8
1DT11	20.0	888.0	38.9	12.2	3.2	54.3	0.28	0.28	22.6
1DT12	25.0	888.0	37.5	13.6	1.4	52.5	0.28	0.28	21.9
1DT13	30.0	888.0	33.9	15.5	2.0	51.4	0.28	0.28	20.2

5.3.2.5 Effect of Carbon Dioxide/Nitrogen Partial Pressure

As stated previously, the pressure at which the immiscible WAG process is carried out is an important factor that determines the process efficiency. When a carbon dioxide-nitrogen mixture is used in place of pure carbon dioxide, the partial pressure of carbon dioxide is less than the total pressure since it is equal to the total pressure less the partial pressure of nitrogen, according to Dalton's law of partial pressure, i.e, $p_T = p_{N_2} + p_{CO_2}$.

To observe the effect of carbon dioxide partial pressure in the presence of nitrogen, the carbon dioxide partial pressure was raised to the total pressure of 1 MPa in Runs 1DT1 to 1DT6, using the equation on the next page.

$$p_T = \frac{p_{CO_2}}{y_{CO_2}},$$

where

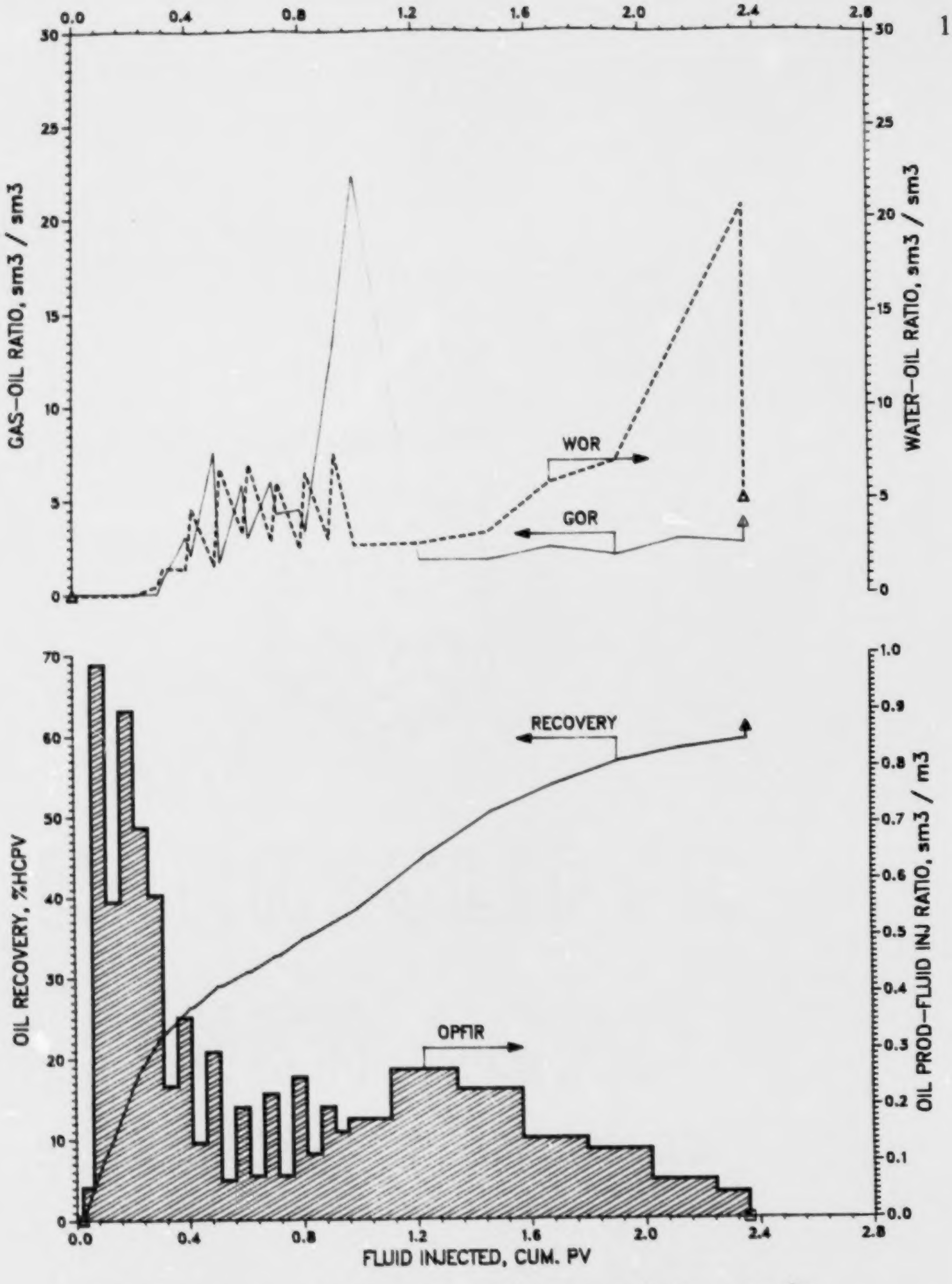
p_T = total or experimental pressure,
p_{CO_2} = partial pressure of CO_2,
y_{CO_2} = mole fraction of CO_2 in the N_2-CO_2 mixture.

Since p_{CO_2} was preset to 1.0 MPa and y_{CO_2} was known, the required experimental (total) pressure was easily determined.

Three runs were carried out to investigate the effect of partial pressure. These were Runs 1DT14, 1DT15, and 1DT16. The mixtures used in these three runs contained nitrogen concentrations of 15.0, 25.0, and 30.0 mole%, respectively. Therefore, to have a carbon dioxide partial pressure of 1.0 MPa, the experimental pressures were 1.2, 1.35, and 1.44 MPa, respectively. The tabulated results of Runs 1DT14 to 1DT16 are presented in Tables A14 to A16 (Appendix A).

Figures 5.40 to 5.42 show the production histories of the three runs. These figures are arranged in the order of increasing nitrogen concentration in the nitrogen-carbon dioxide mixture and increasing experimental pressure. These production curves show that the recoveries were 61.0, 56.9 and 55.8% for Runs 1DT14, 1DT15, and 1DT16, respectively. Even though these runs were conducted with the same carbon dioxide partial pressure (i.e. 1.0 MPa) but with different nitrogen partial pressures, they produced different recoveries; and these recoveries decreased with increasing nitrogen partial pressure in the nitrogen-carbon dioxide system.

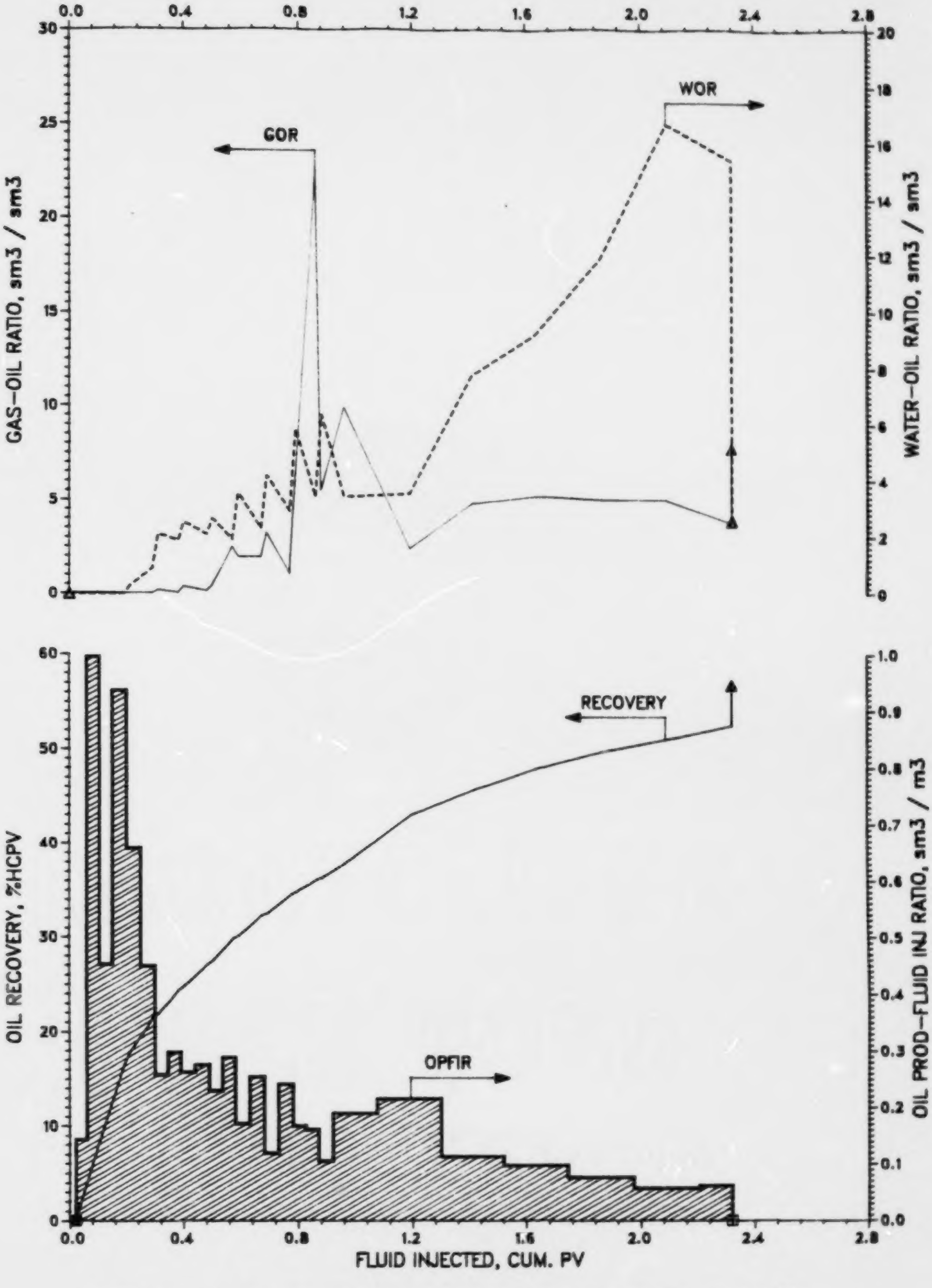
For an explanation, consider the partial pressure and volume of nitrogen for each run. As already mentioned, the nitrogen partial pressures were 0.2, 0.35, and 0.44 MPa for Runs 1DT14, 1DT15, and 1DT16, respectively; and the nitrogen partial volumes were 15.0, 25.0, and 30.0 mole%, respectively. It is expected that Run 1DT16, with the highest nitrogen partial pressure, would yield the highest recovery amongst the three runs. It turned out that this run gave the lowest recovery. The same thing was noted when comparing Runs 1DT15 to 1DT14. Another illustration is provided by Figure 5.43, where the producing GOR's of three runs are plotted and compared. As shown, the GOR curve of Run 1DT16 is the highest amongst the three. This implies that less carbon dioxide diffused into oil and a larger free gas phase of relatively higher relative permeability appeared in this run, compared to Runs 1DT14 and 1DT15. It can be concluded that, under these three



NOTE: Average Run Conditions: Direct Line Drive, 1.20 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.90 %, k = 11.690 darcies, S_o = 95.51 %, S_{wc} = 4.49 %

[0.20 HCPV CO2–N2 @ 1.2 MPa (0.111 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.00%

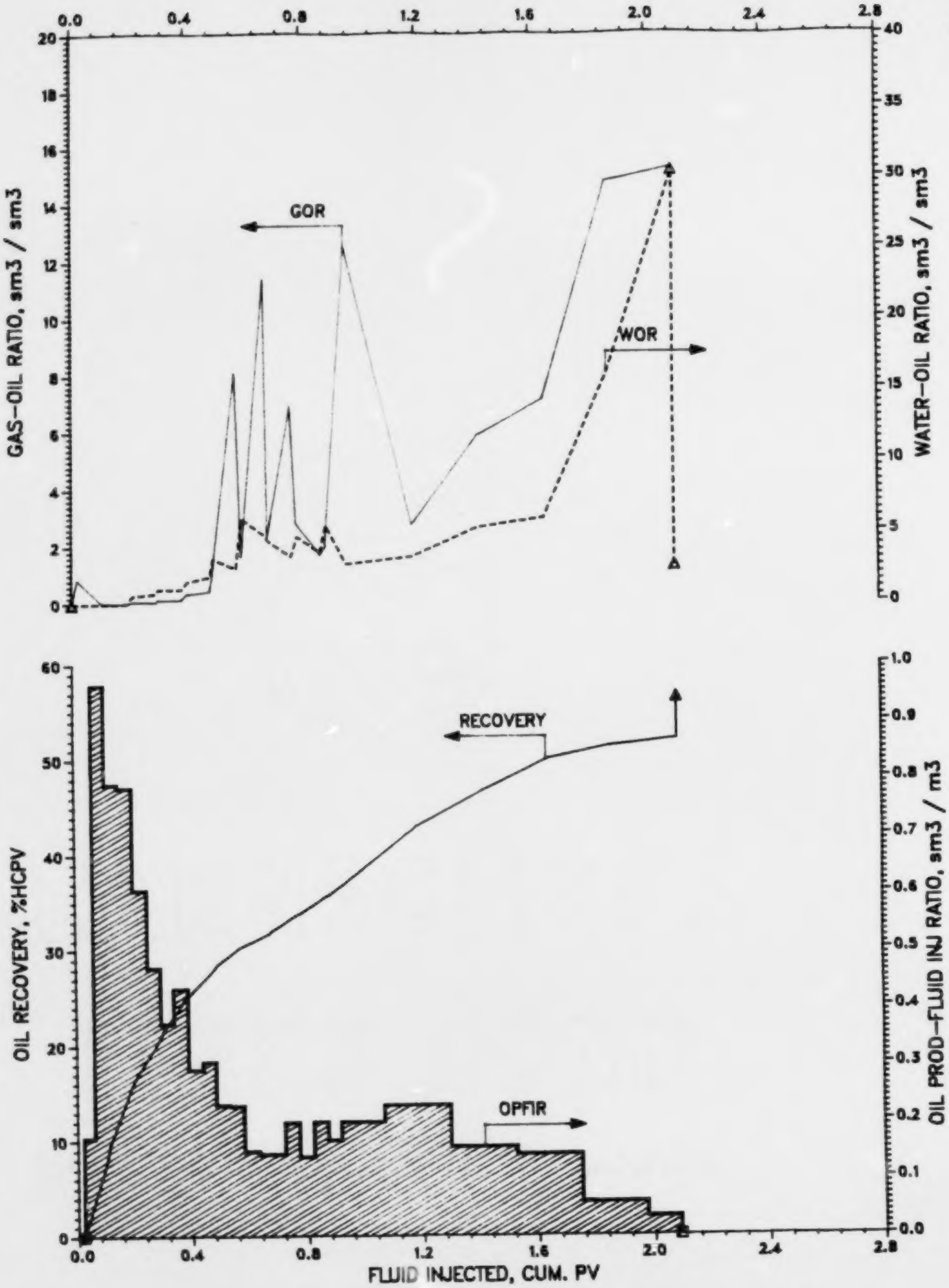
Figure 5.40 – Production History of Run 1DT14.



NOTE: Average Run Conditions: Direct Line Drive, 1.35 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.43 %, k = 10.780 darcies, S_o = 95.46 %, S_{wc} = 4.54 %

[0.20 HCPV CO2–N2 @ 1.35 MPa (0.122 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 25.00%

Figure 5.41 – Production History of Run 1DT15.



NOTE: Average Run Conditions: Direct Line Drive, 1.44 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.51 %, k = 10.020 darcies, S_o = 95.12 %, S_{wc} = 4.88 %

[0.20 HCPV CO2–N2 @ 1.44 MPa (0.130 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 30.00%

Figure 5.42 – Production History of Run 1DT16.

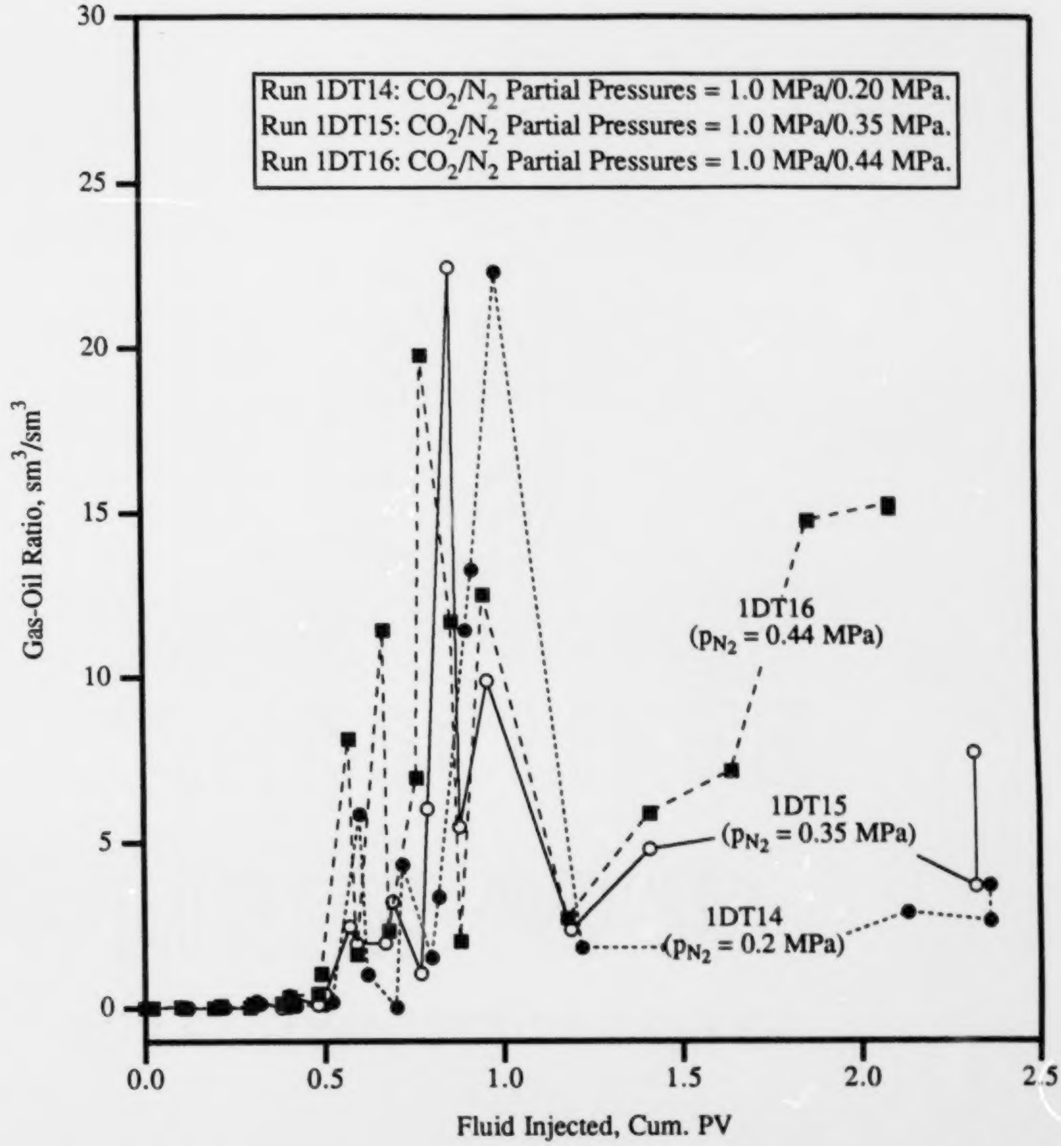


Figure 5.43 - Comparison of Producing GOR's of Runs 1DT14 to 1DT16.

partial pressures, the non-condensibility of nitrogen gas was the dominant effect and led to a reduction in oil recovery.

Figures 5.44 to 5.45 provide a comparison of Run 1DT14 with Runs 1DT7 (utilizing pure carbon dioxide at 1.0 MPa) and 1DT10 (utilizing a 15 mole% nitrogen-85 mole% carbon dioxide mixture at 1.0 MPa). Figure 5.44 shows that the presence of nitrogen in Run 1DT14 led to the production of a larger gas volume than Run 1DT7, even though the carbon dioxide partial pressure (i.e. 1.0 MPa) was the same. This figure also shows that Run 1DT10, because of lower nitrogen and carbon dioxide partial pressures (0.15 MPa and 0.85 MPa, respectively), produced the highest gas volume. The three production curves in Figure 5.45 demonstrate that a higher oil recovery was obtained with a higher carbon dioxide partial pressure. Also, the oil recovery in Run 1DT14 was 2.1% higher than that in Run 1DT7. This extra recovery was probably due to the extra driving force exerted by the 0.2 MPa nitrogen partial pressure in Run 1DT14.

Similarly, Figures 5.46 and 5.47 show the comparisons of Run 1DT15 with Runs 1DT12 (utilizing a 25.0 mole% nitrogen-75.0 mole% carbon dioxide mixture at 1.0 MPa) and 1DT7 (utilizing pure carbon dioxide at 1.0 MPa). Figures 5.48 and 5.49 compare Run 1DT16 with Runs 1DT13 (utilizing a 30.0 mole% nitrogen-70 mole% carbon dioxide mixture at 1.0 MPa) and 1DT7 (utilizing pure carbon dioxide). The same phenomena as above were observed, except that the recoveries of Runs 1DT15 and 1DT16 were noted to be lower than that of Run 1DT7. This was probably due to the large amounts of nitrogen in the mixtures used in Runs 1DT15 (25 mole%) and 1DT16 (30.0 mole%) which caused great resistance to carbon dioxide diffusion into oil, resulting in a loss of oil recovery.

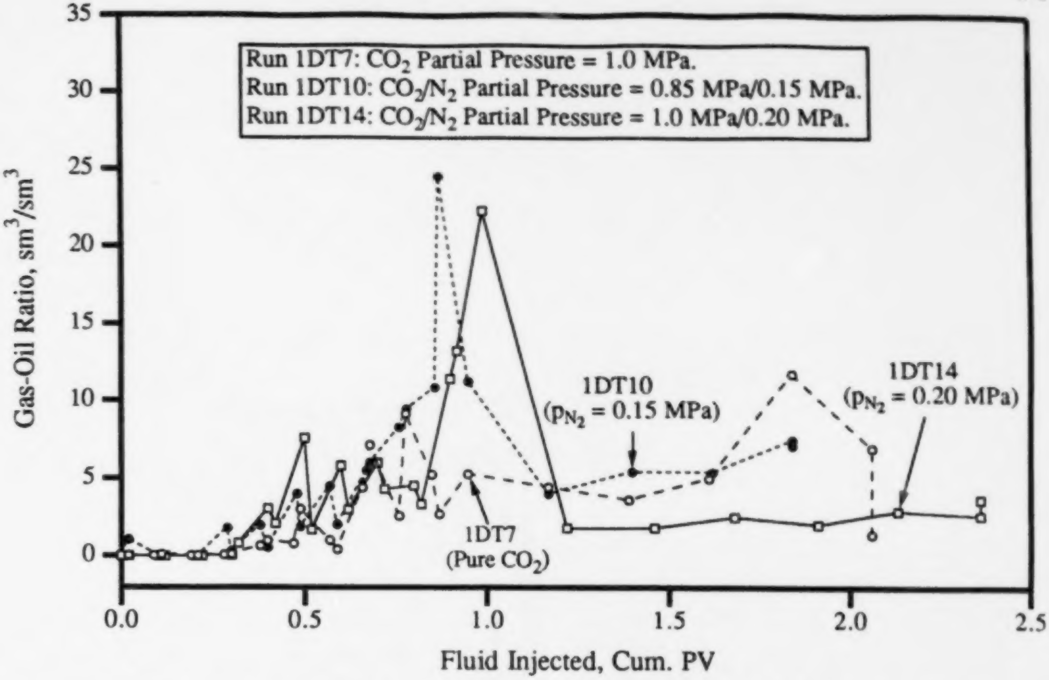


Figure 5.44 - Effect of Carbon Dioxide Partial Pressure on Producing GOR's (Run 1DT14 vs. Runs 1DT7 & 1DT10).

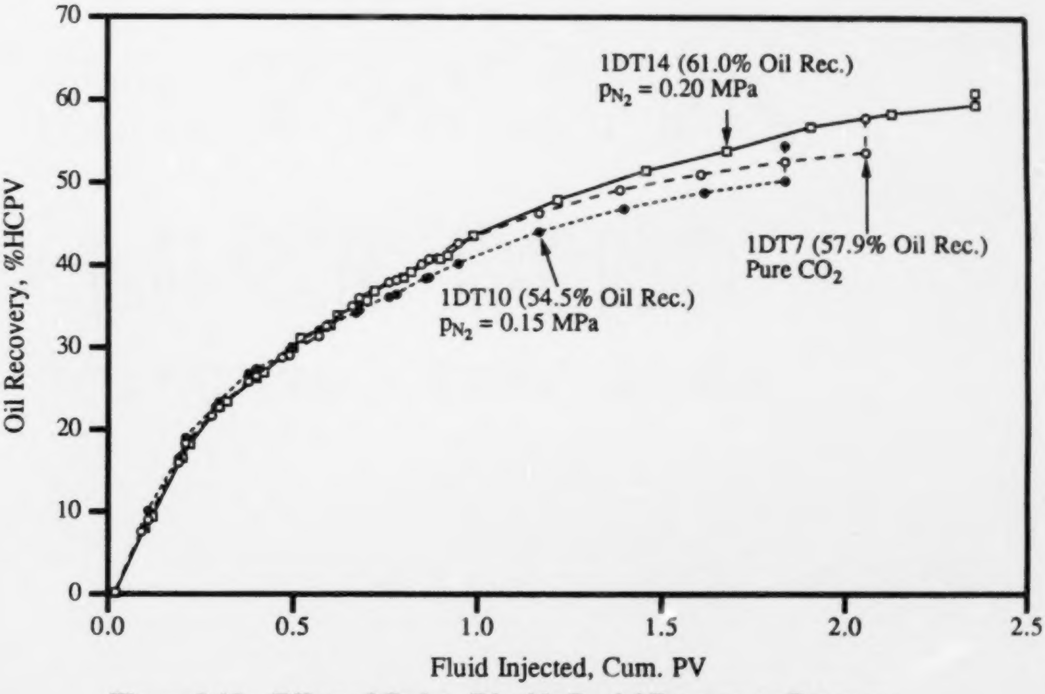


Figure 5.45 - Effect of Carbon Dioxide Partial Pressure on Recovery (Run 1DT14 vs. Runs 1DT7 & 1DT10).

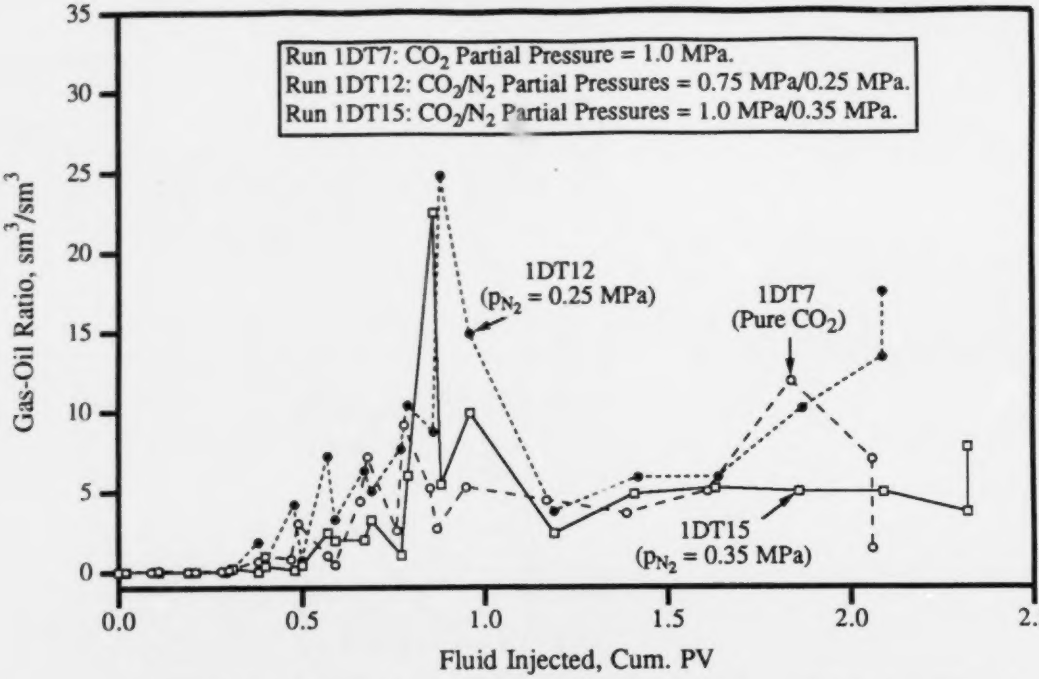


Figure 5.46 - Effect of Carbon Dioxide Partial Pressure on Producing GOR's (Run 1DT15 vs. Runs 1DT7 & 1DT12).

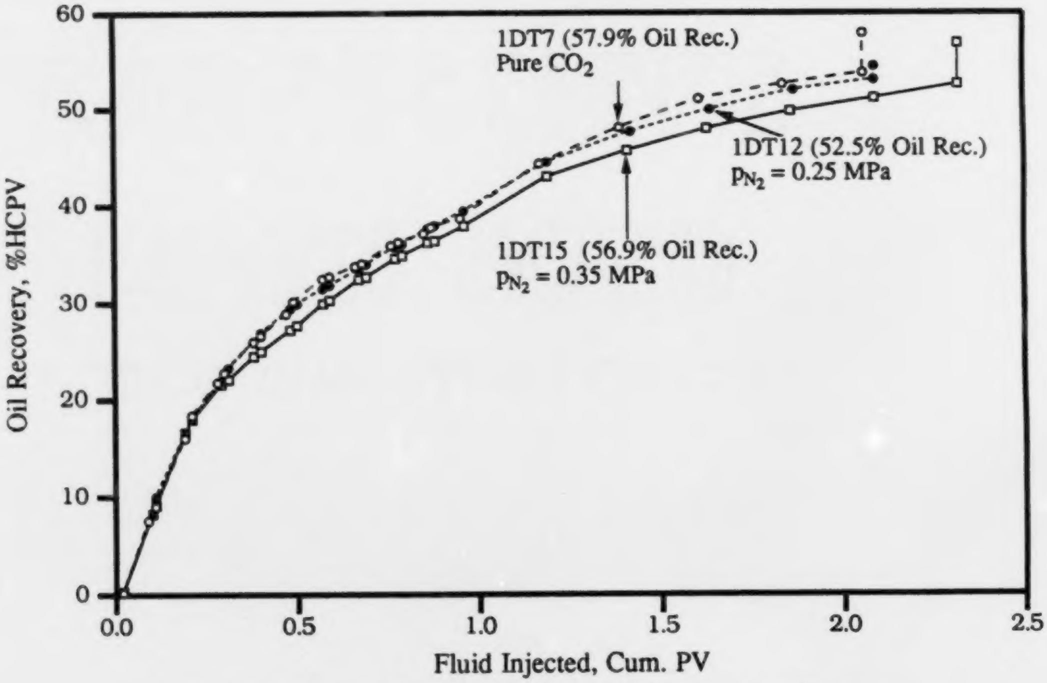


Figure 5.47 - Effect of Carbon Dioxide Partial Pressure on Recovery (Run 1DT15 vs. Runs 1DT7 & 1DT12).

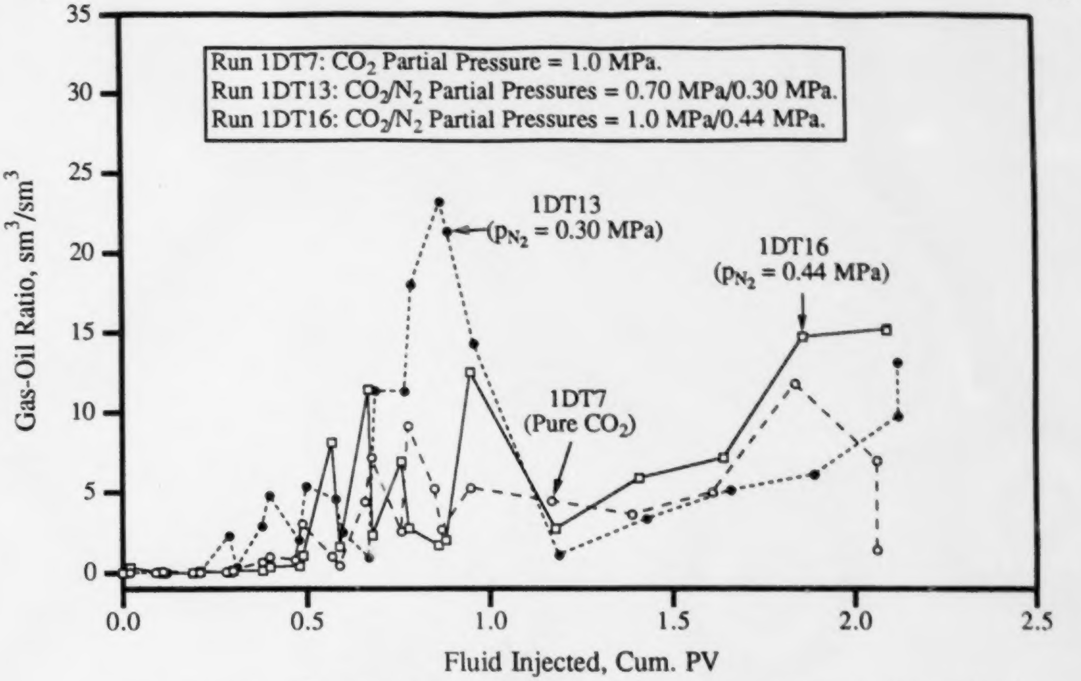


Figure 5.48 - Effect of Carbon Dioxide Partial Pressure on Producing GOR's (Run 1DT16 vs. Runs 1DT7 & 1DT13).

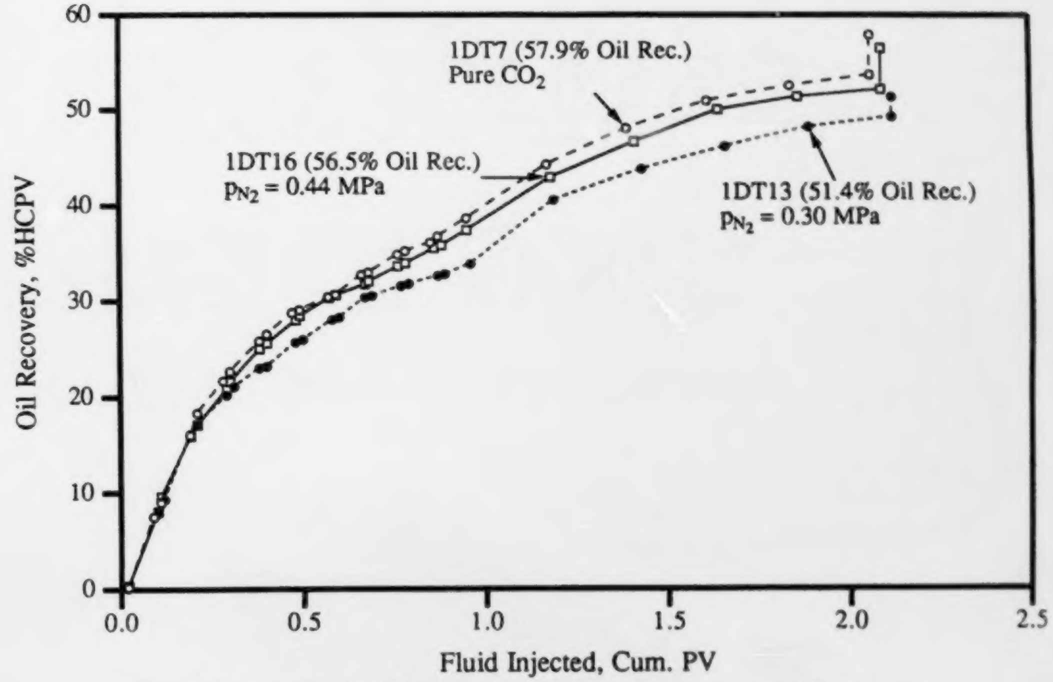


Figure 5.49 - Effect of Carbon Dioxide Partial Pressure on Recovery (Run 1DT16 vs. Runs 1DT7 & 1DT13).

5.3.2.6 Effect of Carbon Dioxide/Nitrogen Partial Volume

Since nitrogen-carbon dioxide mixtures of various compositions were used in this study, the effect of carbon dioxide/nitrogen partial volume was examined as well. For this purpose, the partial volume of carbon dioxide in a nitrogen-carbon dioxide mixture was increased to equal the volume of pure carbon dioxide by applying Amagat's law of partial volumes, which is stated as follows:

$$V_T = \frac{V_{CO_2}}{y_{CO_2}},$$

where

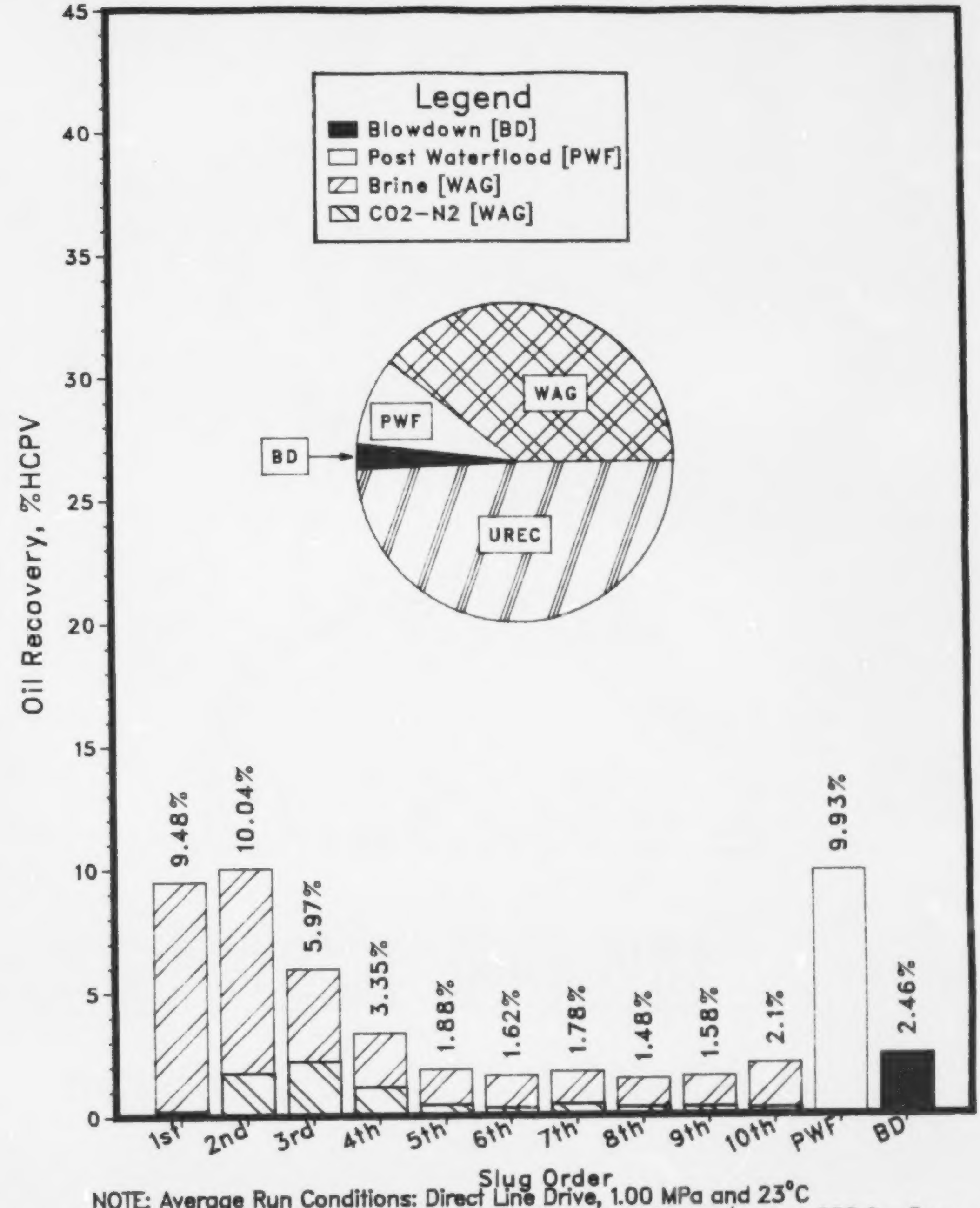
V_T = total volume or total gas slug size,
V_{CO_2}= partial volume of CO_2,
y_{CO_2} = mole fraction of CO_2 in the N_2-CO_2 mixture,

As in the preceding section, V_{CO_2} was preset equal to 20% HCPV, and using y_{CO_2} the total gas slug size, V_T could be found.

Three runs, 1DT17, 1DT18, and 1DT19 were conducted to study the sensitivity of oil recovery to the carbon dioxide partial volume in the presence of nitrogen. As before, mixtures containing 15.0, 25.0, and 30.0 mole% nitrogen were employed in these runs. From the law of partial volumes, the total volumes of a gas mixture injected in Runs 1DT17, 1DT18, and 1DT19 were 23.53, 26.67, and 28.57% HCPV, respectively. Thus, the corresponding nitrogen partial volumes injected were 3.53, 6.67, and 8.57% HCPV, respectively. The conditions at which each run was conducted were 1.0 MPa and 23°C. The WAG ratio used was 4:1. Tables A17 to A19 in Appendix A contain the results of the three experiments.

Figures 5.50 to 5.52 depict the slug recovery distribution of the three runs. The total recoveries were 51.7, 51.6, and 51.4% for Runs 1DT17, 1DT18, and 1DT19, respectively. These recovery values show an insignificant decrease in oil recovery with increasing nitrogen partial volume and decreasing carbon dioxide partial pressure.

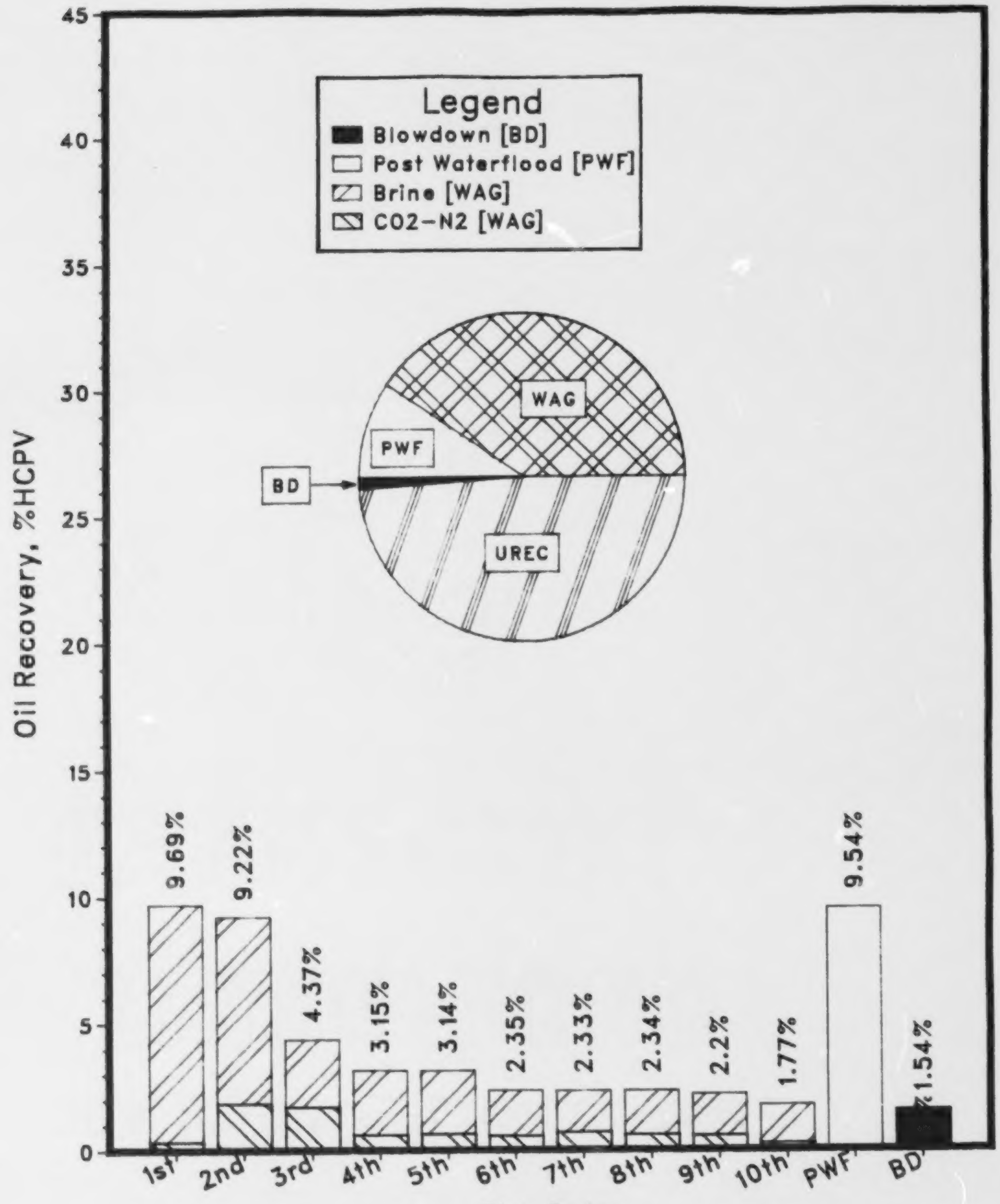
Figure 5.53 compares Run 1DT17 with Runs 1DT7 utilizing pure carbon dioxide and 1DT10 utilizing a 20% HCPV total slug size of 15 mole% nitrogen-85 mole% carbon dioxide mixture. It is seen that Runs 1DT7 and 1DT17 conducted with the same partial volume of carbon dioxide gave different recoveries. The recovery for Run 1DT7 was about 6.2% HCPV higher. Possible explanations are that there was no non-condensible



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.61 %, k = 10.240 darcies, S_o = 95.59 %, S_{wc} = 4.41 %

[0.24 HCPV CO2–N2 @ 1.0 MPa (0.106 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.0%.
Total Oil Recovery = 51.7 %HCPV

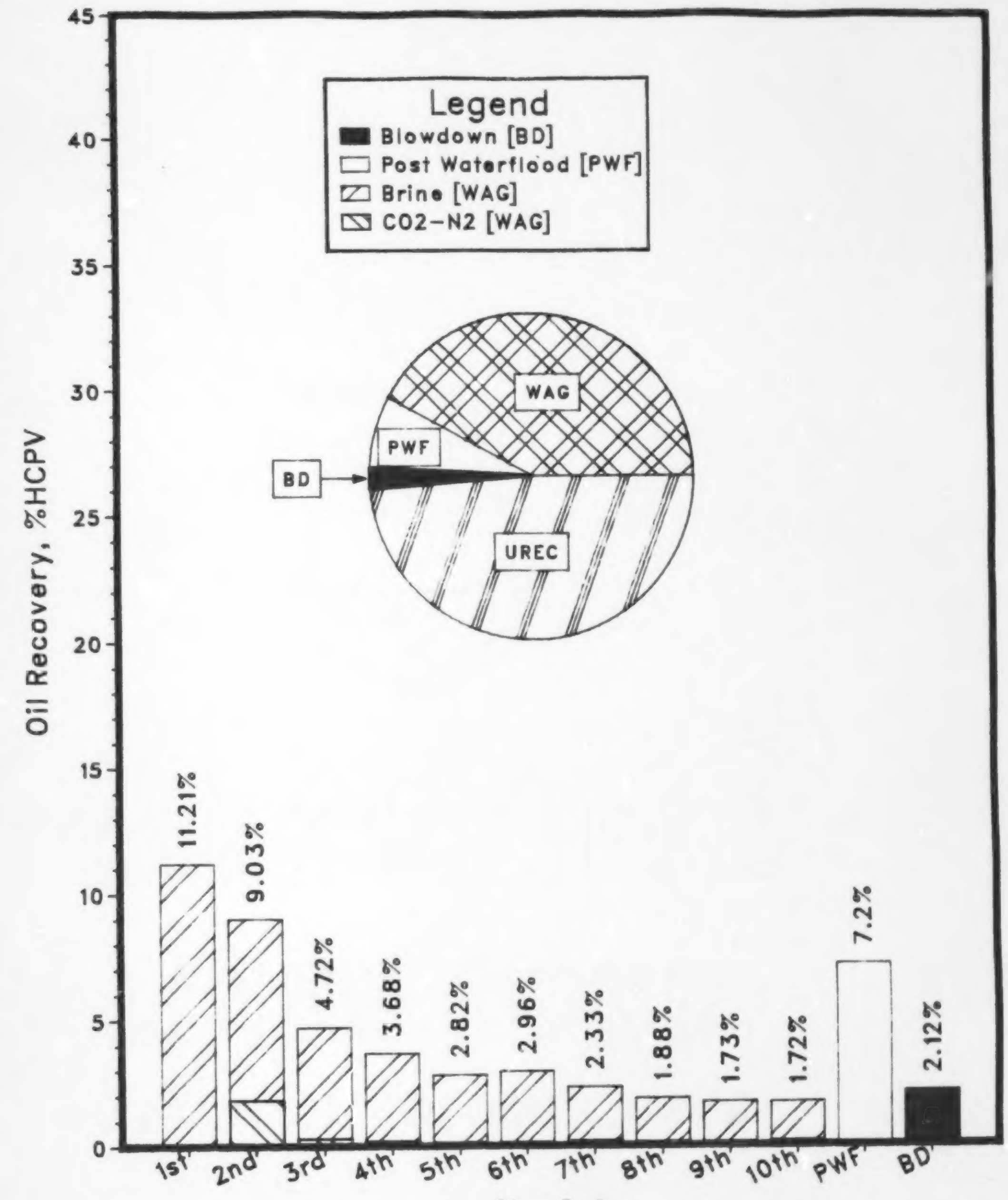
Figure 5.50 – Oil Recovery Distribution of Run 1DT17.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.64 %, k = 11.280 darcies, S_o = 94.60 %, S_{wc} = 5.40 %

[0.27 HCPV CO2–N2 @ 1.0 MPa (0.119 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 25.00%
Total Oil Recovery = 51.6 %HCPV

Figure 5.51 – Oil Recovery Distribution of Run 1DT18.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.91 %, k = 10.990 darcies, S_o = 95.21 %, S_{wc} = 4.79 %

[0.29 HCPV CO2-N2 @ 1.0 MPa (0.129 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 30.00%
Total Oil Recovery = 51.4 %HCPV

Figure 5.52 – Oil Recovery Distribution of Run 1DT19.

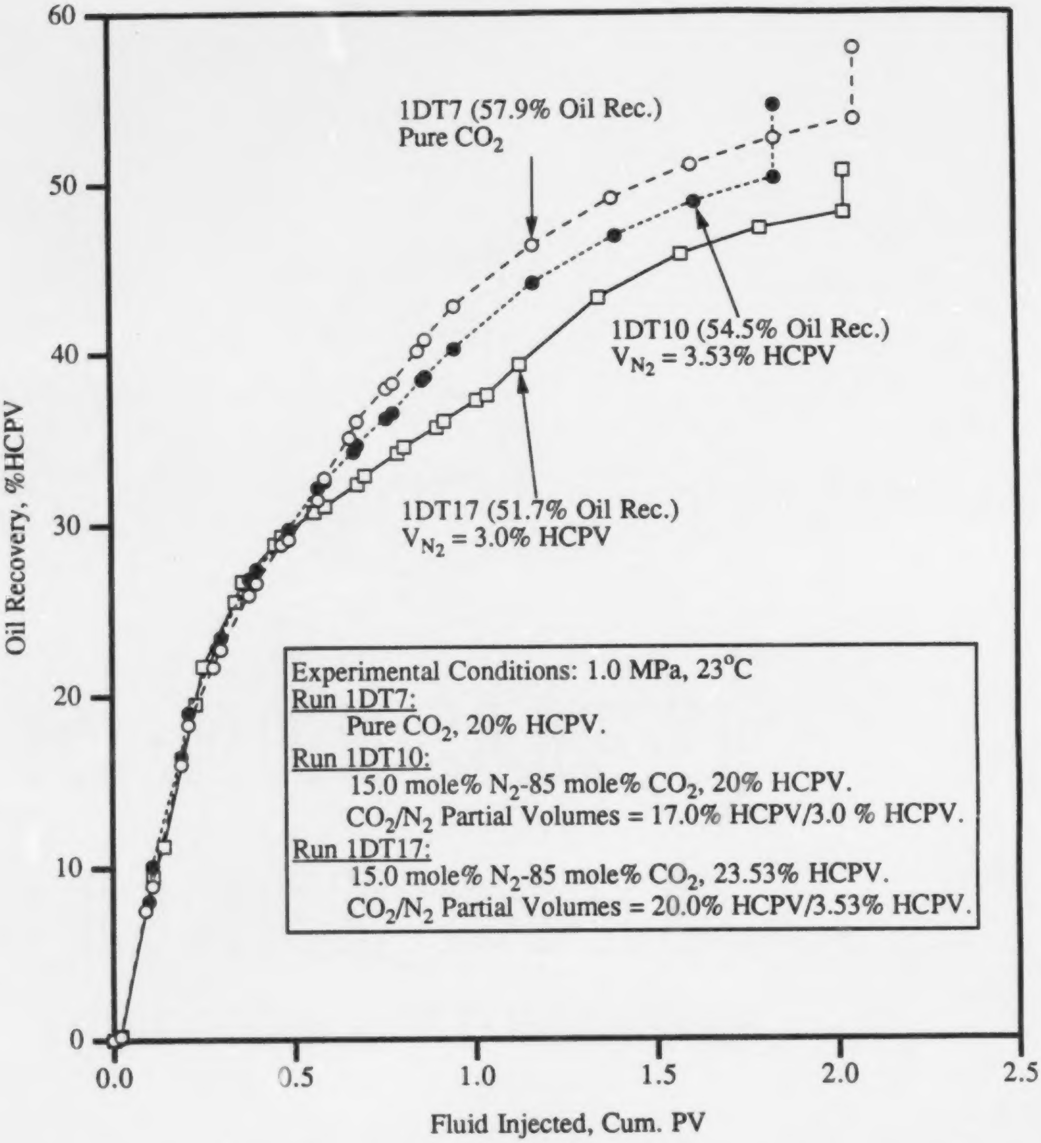


Figure 5.53 - Effect of Carbon Dioxide/Nitrogen Partial Volume on Recovery (Run 1DT17 vs. Runs 1DT7 and 1DT10).

nitrogen gas present in Run 1DT7 and that the partial pressure of carbon dioxide in Run 1DT17 was lower. Regarding the production curves of Runs 1DT17 and 1DT10 in Figure 5.53, it can also be seen that less oil was recovered in Run 1DT17 than in Run 1DT10. These two runs, having been conducted with the same partial pressure of nitrogen, gave different recoveries. This was mainly due to the difference in the partial volume of nitrogen injected: 3.53% HCPV of nitrogen was injected in Run 1DT17 while 3.0% HCPV in Run 1DT10.

Figure 5.54 shows the recovery comparison of Run 1DT18 with Runs 1DT7 utilizing pure carbon dioxide and 1DT12 utilizing a 25.0 mole% nitrogen-75.0 mole% carbon dioxide mixture. As observed above, the recovery for Run 1DT18 was lower than those for Runs 1DT7 and 1DT12. A recovery loss of 0.9% HCPV was noted when comparing Run 1DT8 with Run 1DT12.

Similar to Runs 1DT17 and 1DT18, Run 1DT19 was compared with Runs 1DT7 utilizing pure carbon dioxide and 1DT13 utilizing a 30.0 mole% nitrogen-70.0 mole% carbon dioxide mixture. The comparison is shown in Figure 5.55, clearly showing that a lower oil recovery was obtained in Run 1DT19, as compared to Run 1DT7. Also, it was noted that Runs 1DT13 and 1DT19 had almost the same production history since the two recovery curves nearly overlay and that the recovery difference was only 0.1% HCPV. Based upon this observation, it may be speculated that the partial nitrogen volumes of 6.0% HCPV and 8.57% HCPV used in Runs 1DT13 and 1DT19, respectively, had an almost identical effect on oil recovery.

In conclusion, using the same partial volume of carbon dioxide while increasing the partial volume of nitrogen in the immiscible process lowers oil recovery, as compared to pure carbon dioxide.

5.3.2.7 Comparison of Partial Pressure Runs With Partial Volume Runs

Table 5.6 gives a comparison of carbon dioxide partial pressure runs with carbon dioxide partial volume runs. Clearly, the carbon dioxide partial pressure runs gave higher oil recoveries than carbon dioxide partial volume runs because of the higher carbon dioxide partial pressures and lower partial nitrogen volumes in the former.

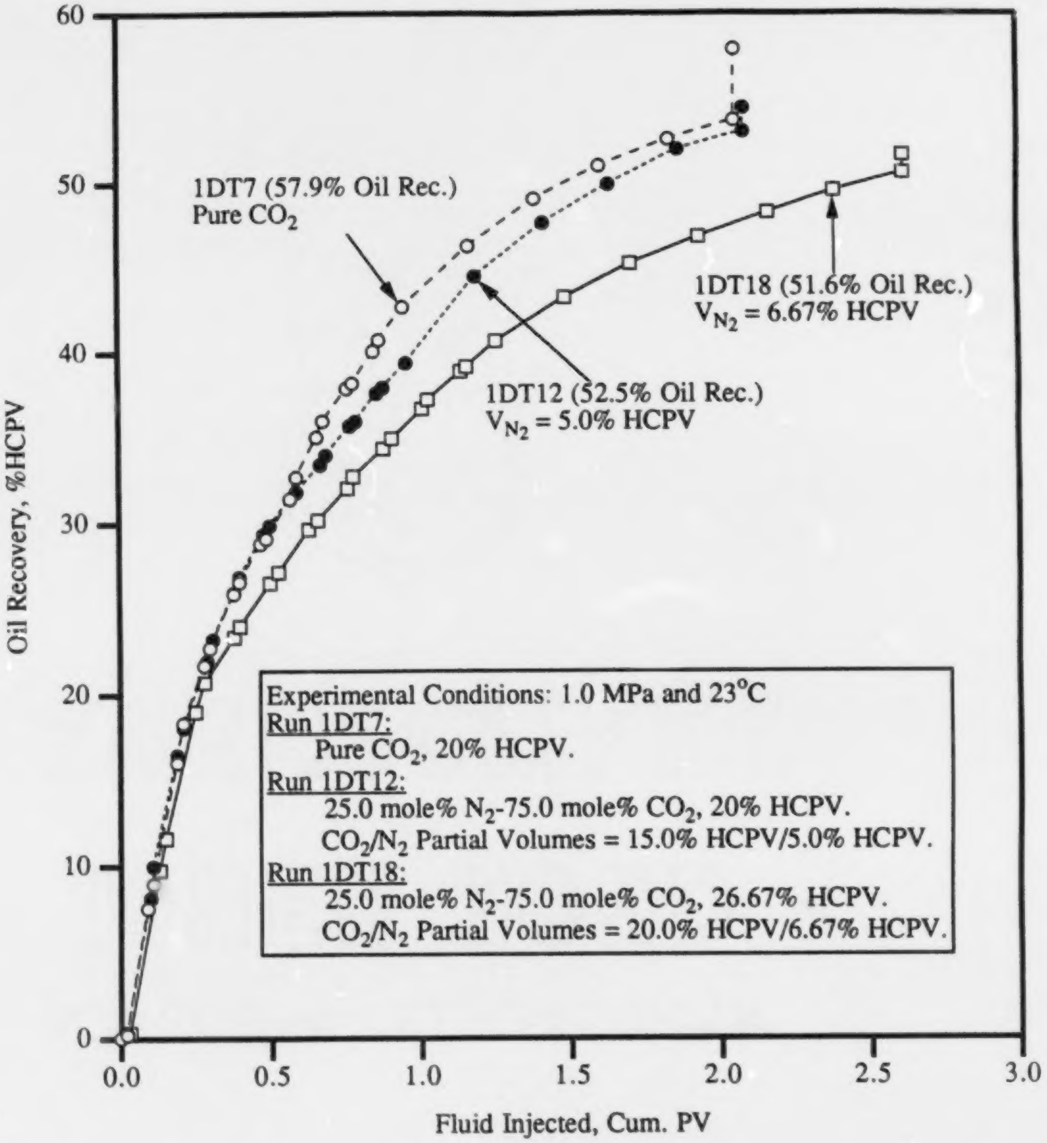


Figure 5.54 - Effect of Carbon Dioxide/Nitrogen Partial Volume on Recovery (Run 1DT18 vs. Runs 1DT7 and 1DT12).

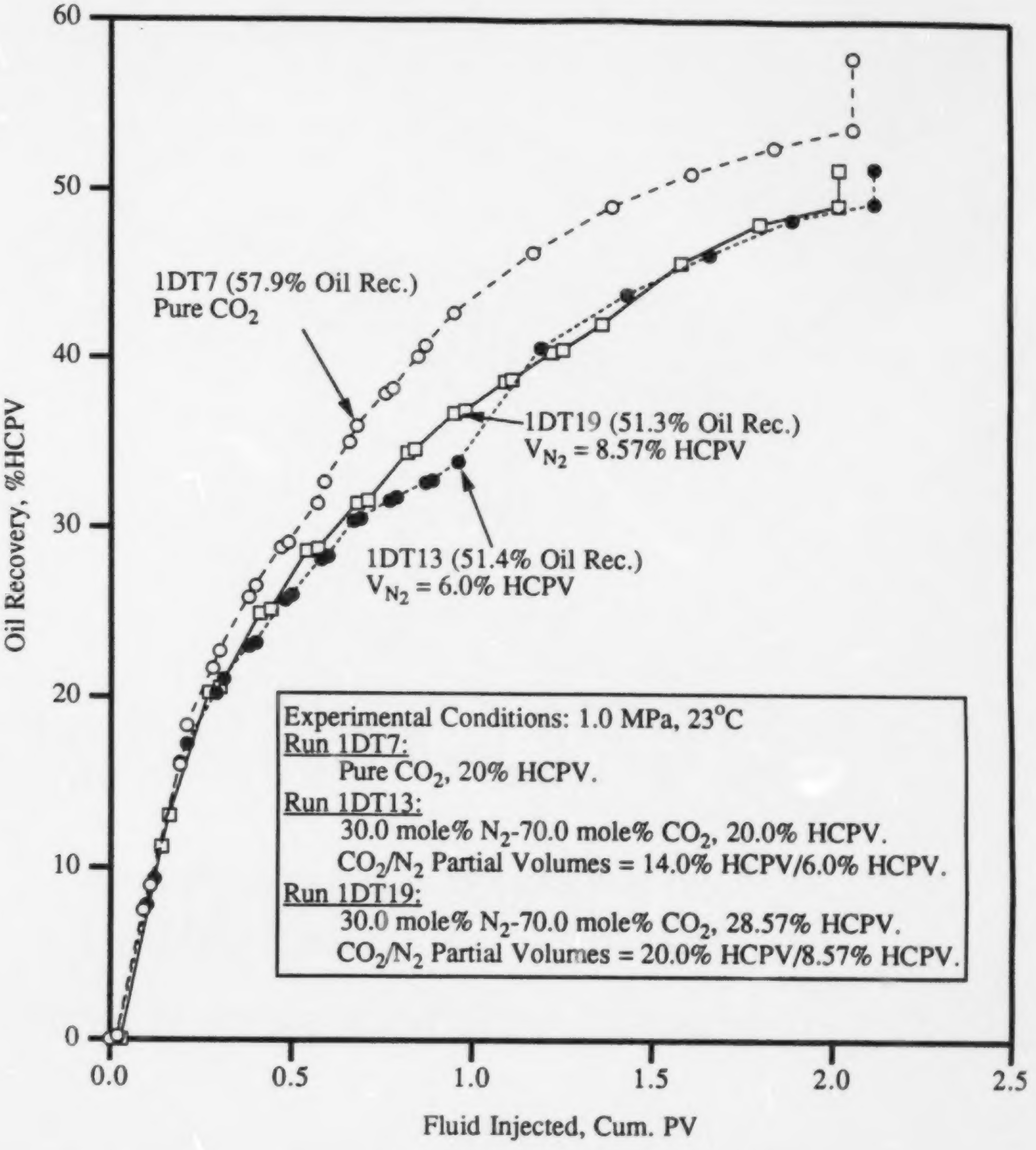


Figure 5.55 - Effect of Carbon Dioxide/Nitrogen Partial Volume on Recovery (Run 1DT19 vs. Runs 1DT7 and 1DT13).

Table 5.6 - Comparison of CO_2 Partial Pressure Runs With CO_2 Partial Volume Runs

Exp. No.	p_{CO_2}/p_{N_2} (MPa)	V_{N_2}/V_{CO_2} (%HCPV)	Recovery (%HCPV)	Exp. No.	p_{CO_2}/p_{N_2} (MPa)	V_{N_2}/V_{CO_2} (%HCPV)	Recovery (%HCPV)
1DT14	1.0/0.20	3.0/17.0	61.0	1DT17	0.85/0.15	3.53/20.0	51.7
1DT15	1.0/0.35	5.0/15.0	56.9	1DT18	0.75/0.25	6.67/20.0	51.6
1DT16	1.0/0.44	6.0/14.0	56.5	1DT19	0.70/0.30	8.57/20.0	51.4

5.3.2.8 Effect of Total Gas Slug Size

Three linear model runs, 1DT20, 1DT21 and 1DT22, were conducted with total slug sizes larger than 20% HCPV to observe if there would be an increase in oil recovery. Run 1DT20 was conducted with a 50% HCPV slug size of a 4.98 mole% nitrogen-95.02 mole% carbon dioxide mixture. Runs 1DT21 and 1DT22 were conducted with a 40% HCPV slug size, and 9.99 and 15.0 mole% nitrogen mixtures, respectively. The experimental results of the three runs are summarized in Tables A20 to A22 in Appendix A.

The recovery distributions for Run 1DT20 were 51.2, 3.2, and 2.7% in the WAG, post-waterflood, and blowdown phases, respectively, totalling 57.1%. A total recovery of 56.2%, made up of 49.4% by WAG, 4.7% by post-waterflooding, and 2.1% by blowdown, was obtained for Run 1DT21. Finally, in Run 1DT22, the oil recovered in the WAG stage was 46.8% followed by the post-waterflood and blowdown recoveries of 4.7 and 3.3%, respectively; this gave a total recovery of 54.8%.

Figures 5.56 to 5.61 compare the results of the linear model Runs 1DT8, 1DT9, and 1DT10 utilizing a total gas slug size of 20% HCPV and 4.98, 9.99, and 15.0 mole% nitrogen mixtures, respectively. Examining Figures 5.56, 5.58, and 5.60 reveals that linear model Runs 1DT20, 1DT21, and 1DT22 recovered more oil in the WAG phase but less in the post-waterflood and blowdown phases than Runs 1DT8, 1DT9, 1DT10, respectively; and that the total recoveries of these runs were nearly identical to those for Runs 1DT8, 1DT9, and 1DT10 (55.5, 54.6, and 54.5%, respectively). A possible explanation is that the larger volumes of gas and water injected in the WAG phase in Runs 1DT20, 1DT21, and 1DT22 resulted in a higher recovery in this phase. Thus, after the WAG phase smaller volumes of oil remained and larger volumes of water appeared in Runs 1DT20, 1DT21, and 1DT22, and lower oil relative permeabilities and higher water relative permeabilities could be expected. As a result, oil became less mobile and smaller volumes

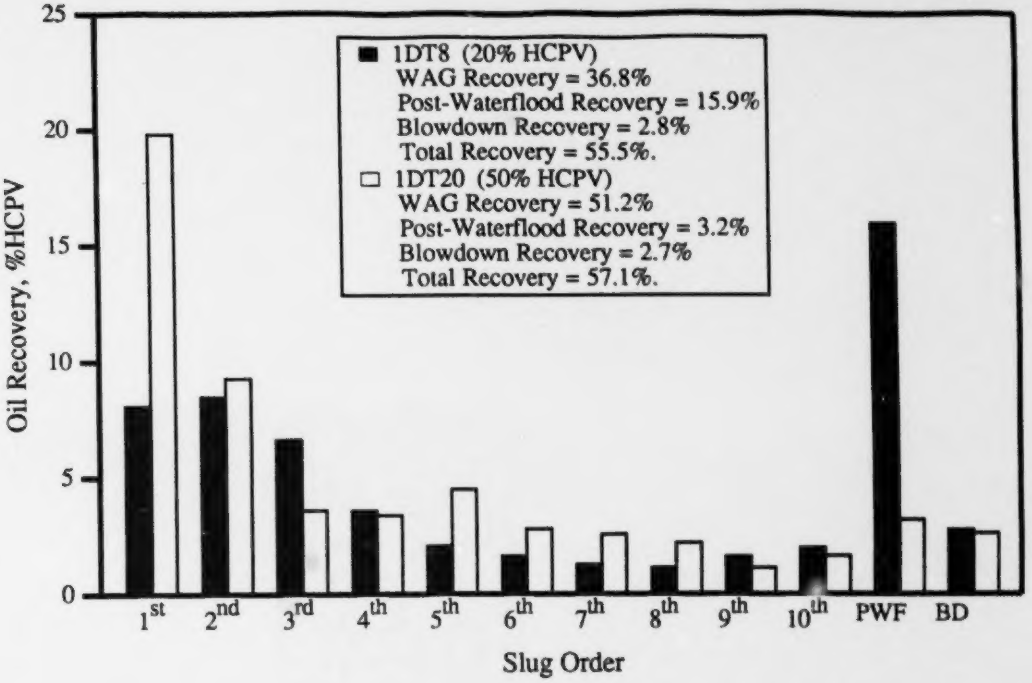


Figure 5.56 - Effect of Slug Size on Recovery (Run 1DT20 vs. Run 1DT8).

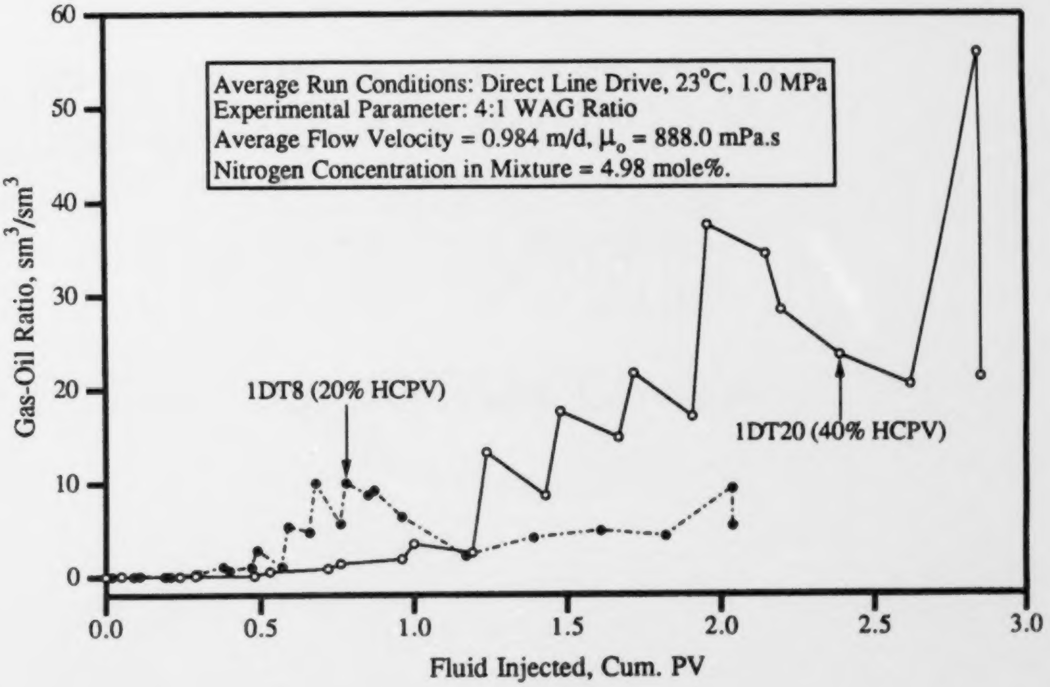


Figure 5.57 - Effect of Slug Size on Producing GOR (Run 1DT20 vs. Run 1DT8).

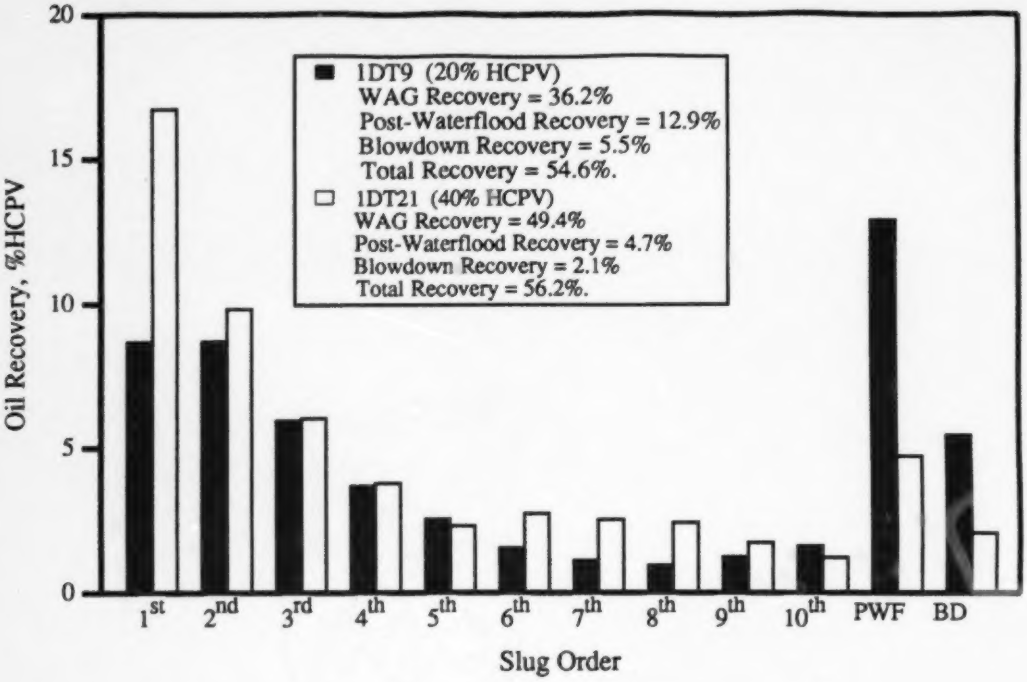


Figure 5.58 - Effect of Slug Size on Recovery (1DT21 vs. 1DT9).

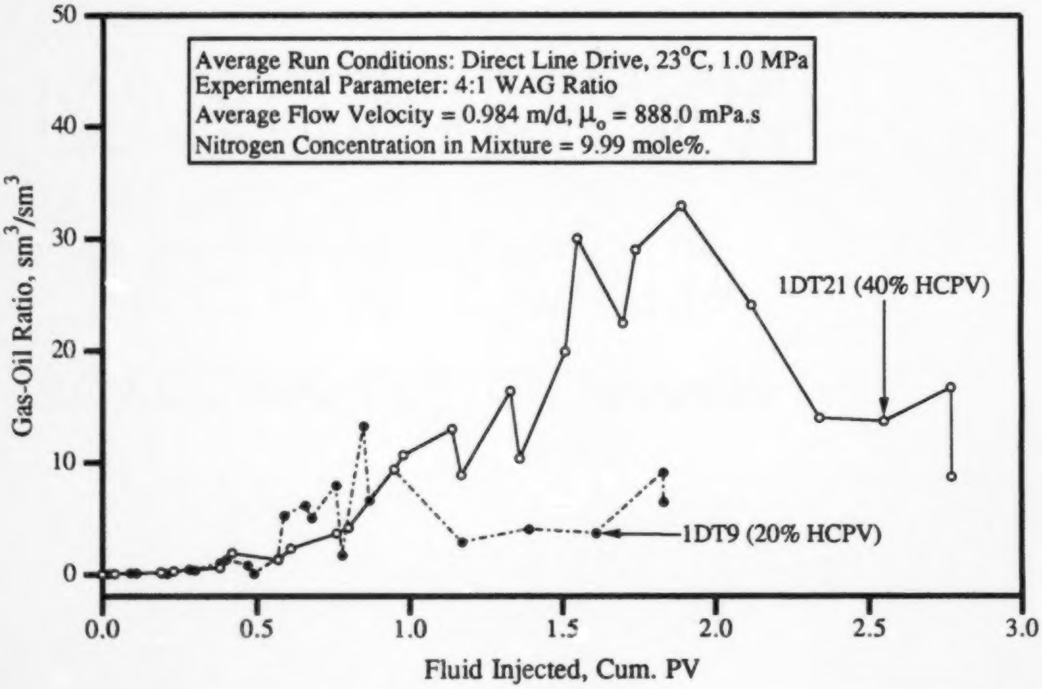


Figure 5.59 - Effect of Slug Size on Producing GOR (Run 1DT21 vs. Run 1DT9).

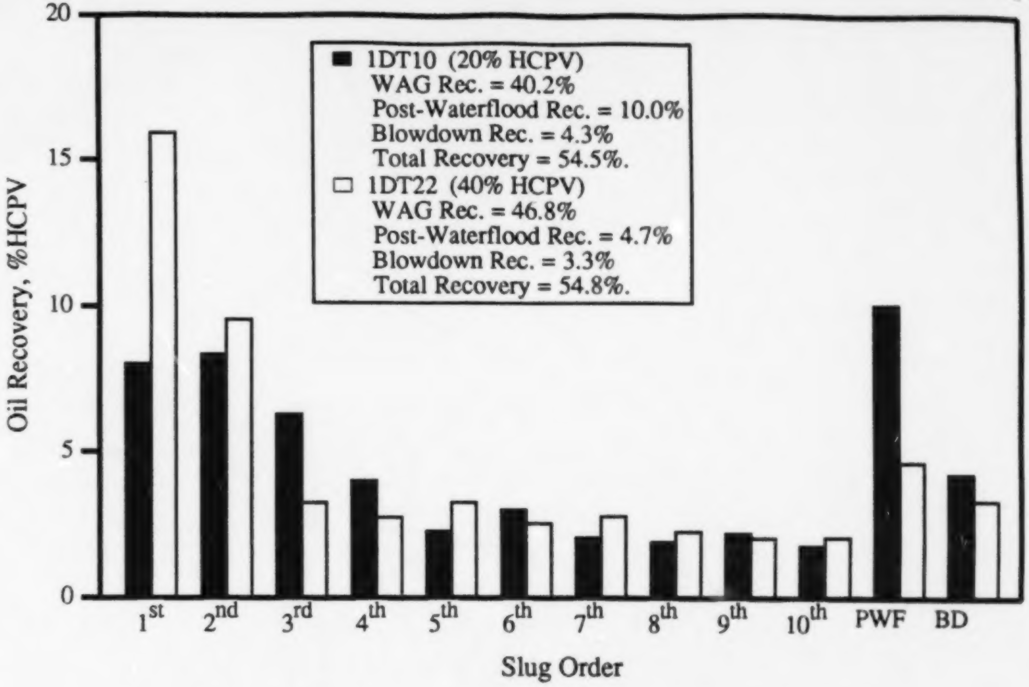


Figure 5.60 - Effect of Slug Size on Recovery (Run 1DT22 vs. 1DT10).

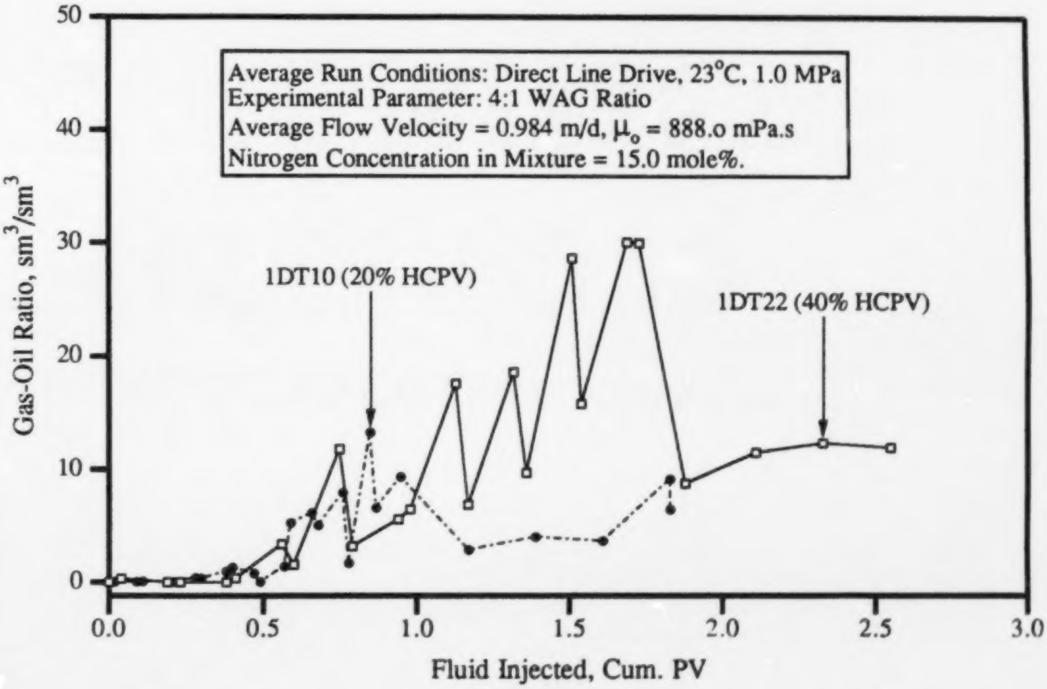


Figure 5.61 - Effect of Slug Size on Producing GOR (Run 1DT22 vs. 1DT10).

of oil were recovered in the post-waterflood and blowdown phases in these runs than in Runs 1DT8 to 1DT10. This evened out the total recovery.

The main reason why the use of a total gas slug size larger than 20% HCPV did not lead to any substantial improvement in oil recovery is that under immiscible conditions, i.e. 1.0 MPa and 23°C, and for the residence time involved, only a certain amount of carbon dioxide injected could diffuse into the oil, while the excess gas volume formed a free mobile gas zone together with nitrogen. During the course of the experiment, this phenomenon was observed by noting a large amount of free gas produced along with oil in Runs 1DT20 to 1DT22. On the producing gas-oil ratio plot, the production of this free gas is indicated by a distinctly higher producing GOR (Figures 5.57, 5.59, 5.61 show the comparisons). The free gas can also be thought to exert a drive which helped to move oil toward the production end. Such a drive was small, and displaced only a small volume of oil. This is why only small increments (i.e. 1.7, 1.6, and 0.3%, respectively) in recovery were observed in Runs 1DT20, 1DT21, and 1DT22, compared to Runs 1DT8, 1DT9, and 1DT10, respectively.

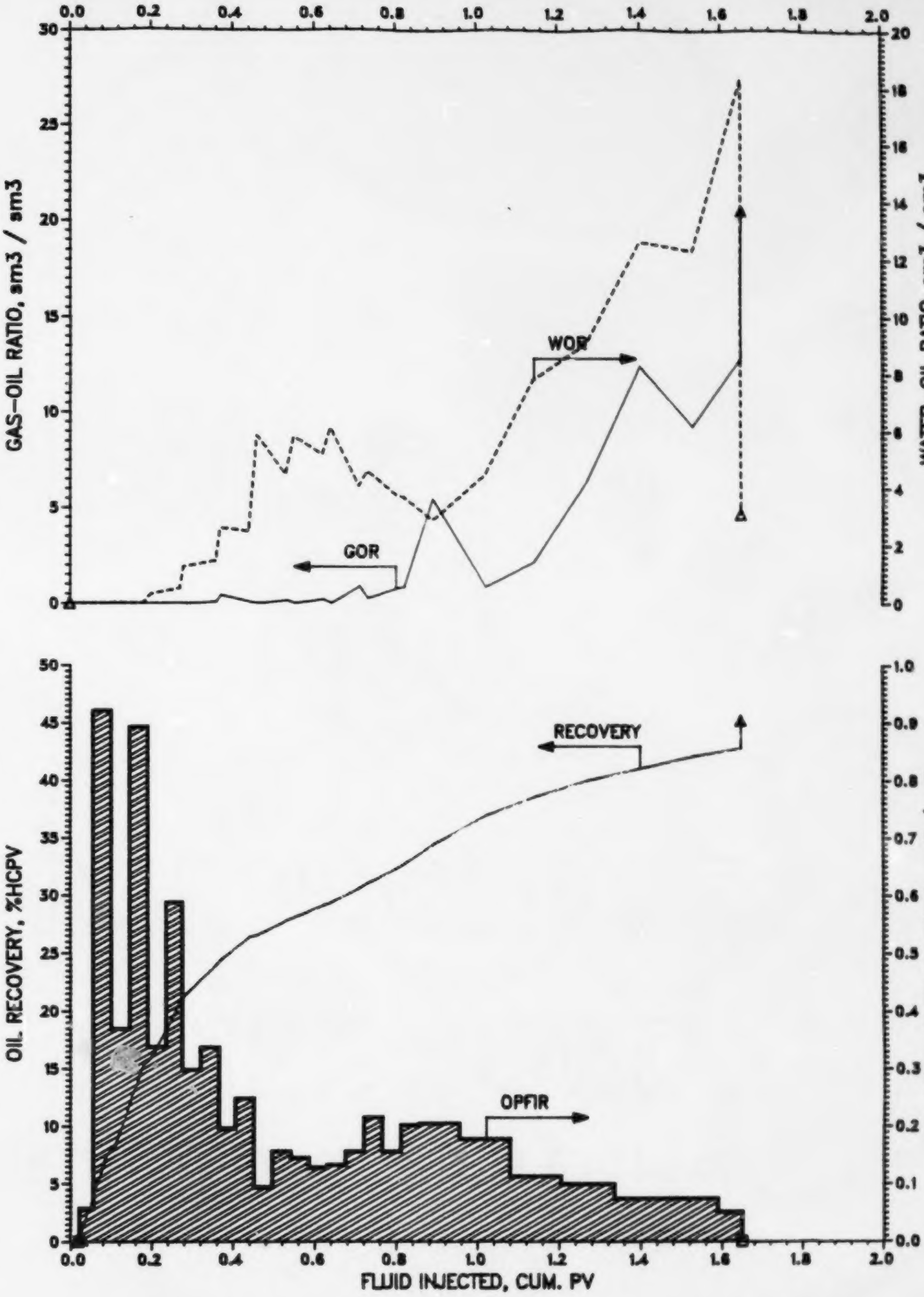
In short, the use of a large total slug led to inefficient utilization of carbon dioxide and did not improve recovery.

Two-Dimensional Model Experiments

This section contains a discussion of experiments conducted in the two-dimensional model. These runs utilized the parameters of selected runs in the linear model. Thus, ten linear model runs were repeated in the two-dimensional model. Table 5.4b contains the results of these runs.

5.3.2.9 Effect of Nitrogen on The Process Displacement Efficiency

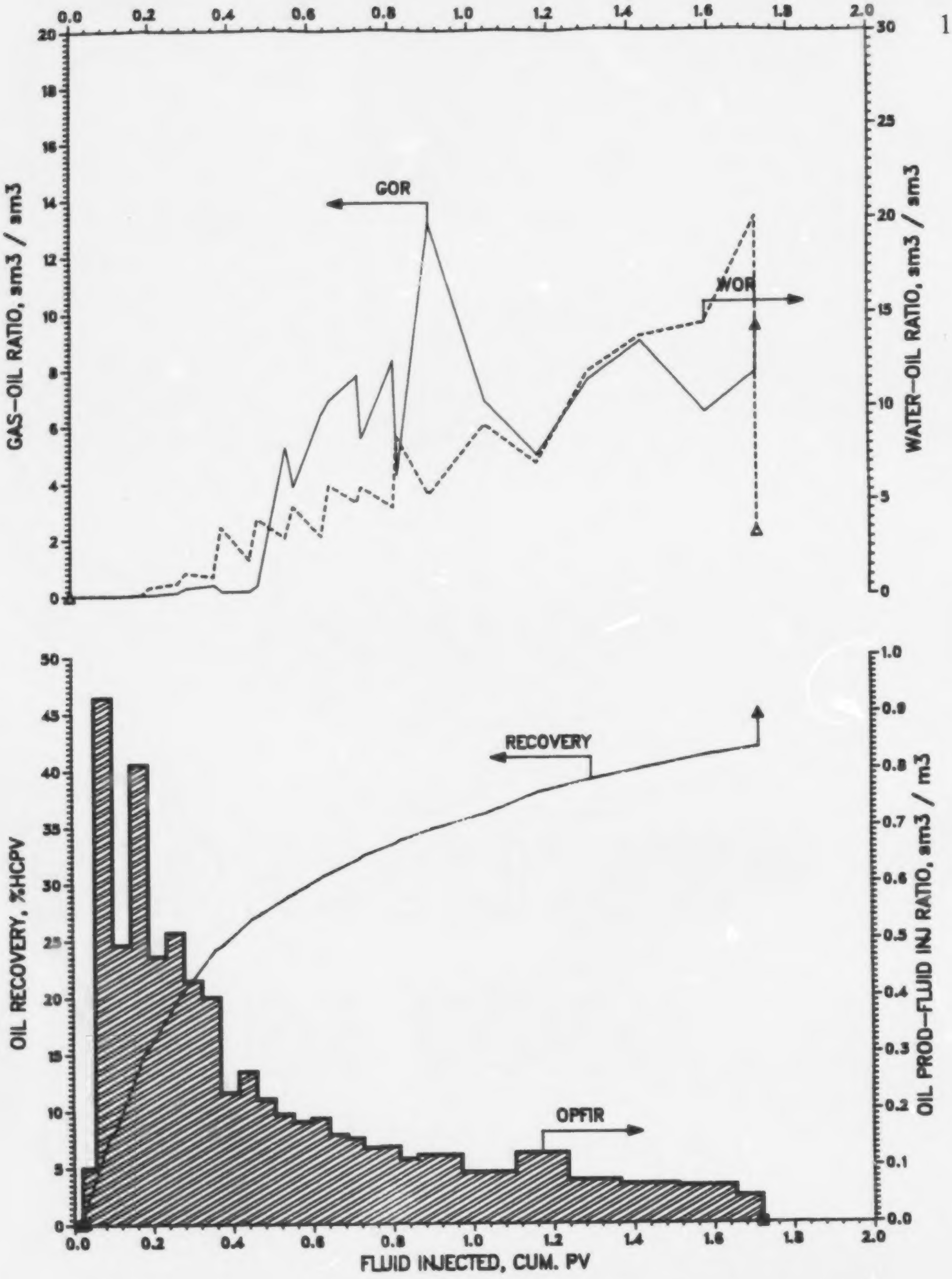
Six linear model runs, 1DT1 to 1DT6, were repeated in the two-dimensional model to study the effect of nitrogen in carbon dioxide on the immiscible carbon dioxide WAG process displacement efficiency, when the process is applied in the field. The six corresponding two-dimensional model runs were 2DT1 to 2DT6. The nitrogen concentrations of the mixtures used in these runs were 4.98, 9.99, 15.0, 20.0, 25.0, and 30.0 mole%, respectively. Tables A33 to A38 contain the tabulated data of the six experiments. Figures 5.62 to 5.67 describe the producing GOR's and production histories of the six runs.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 40.77 %, k = 11.140 darcies, S_o = 88.82 %, S_{wc} = 11.18 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.152 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 4.98%

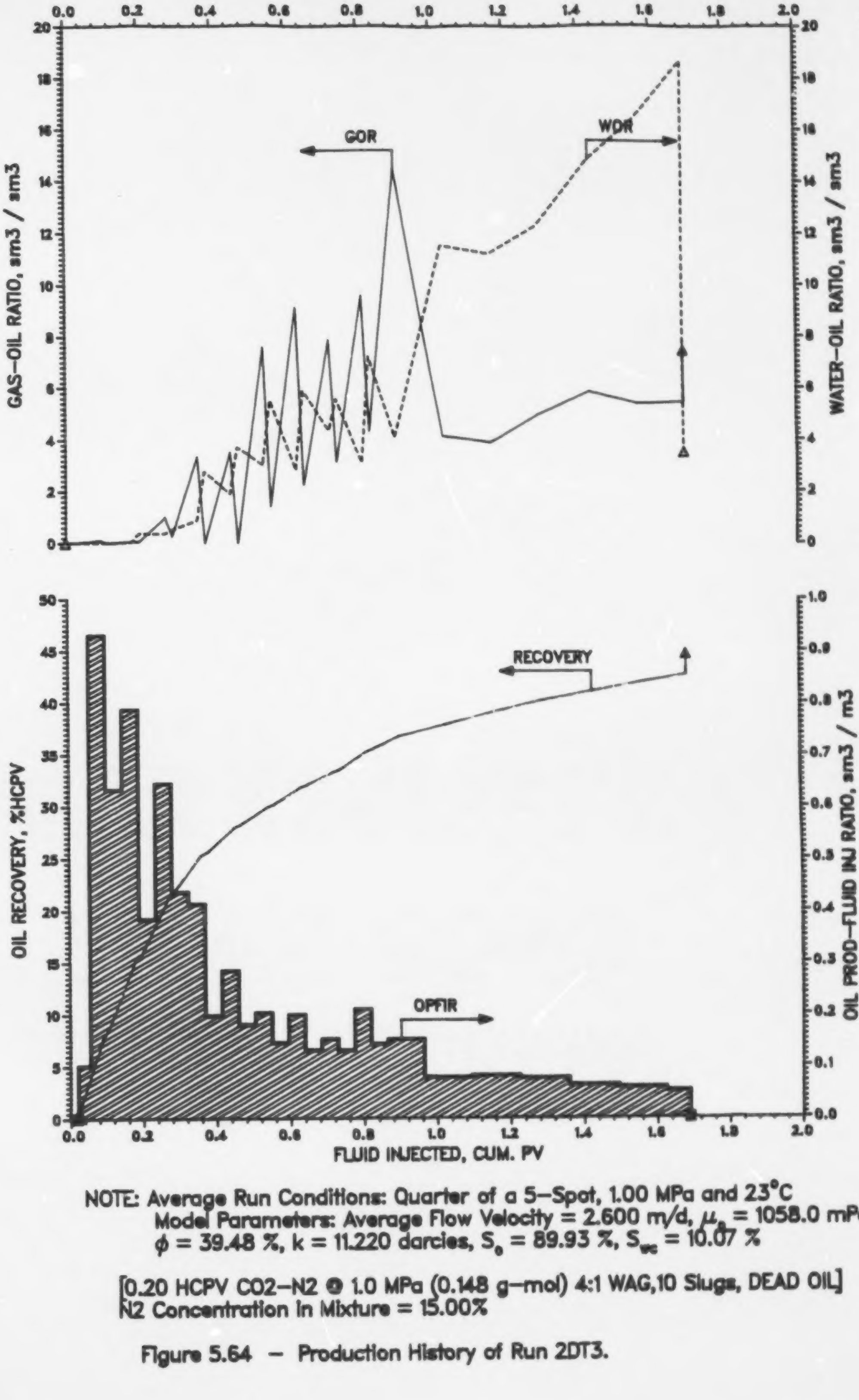
Figure 5.62 – Production History of Run 2DT1.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 40.14 %, k = 11.120 darcies, S_o = 89.51 %, S_{wc} = 10.49 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.150 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 9.99%

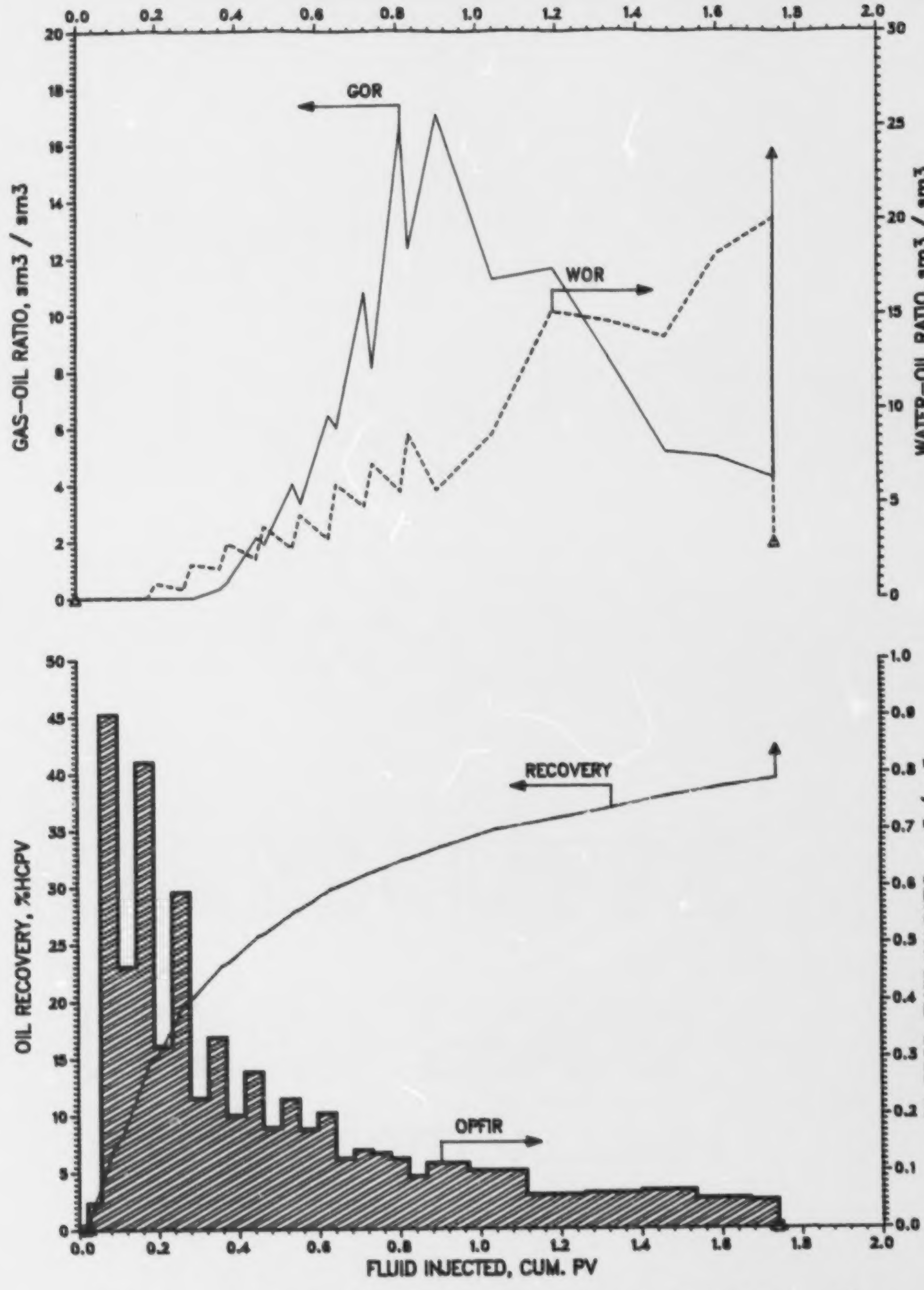
Figure 5.63 – Production History of Run 2DT2.



NOTE: Average Run Conditions: Quarter of a 5-Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 39.48 %, k = 11.220 darcies, S_o = 89.93 %, S_{wc} = 10.07 %

[0.20 HCPV CO2-N2 @ 1.0 MPa (0.148 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.00%

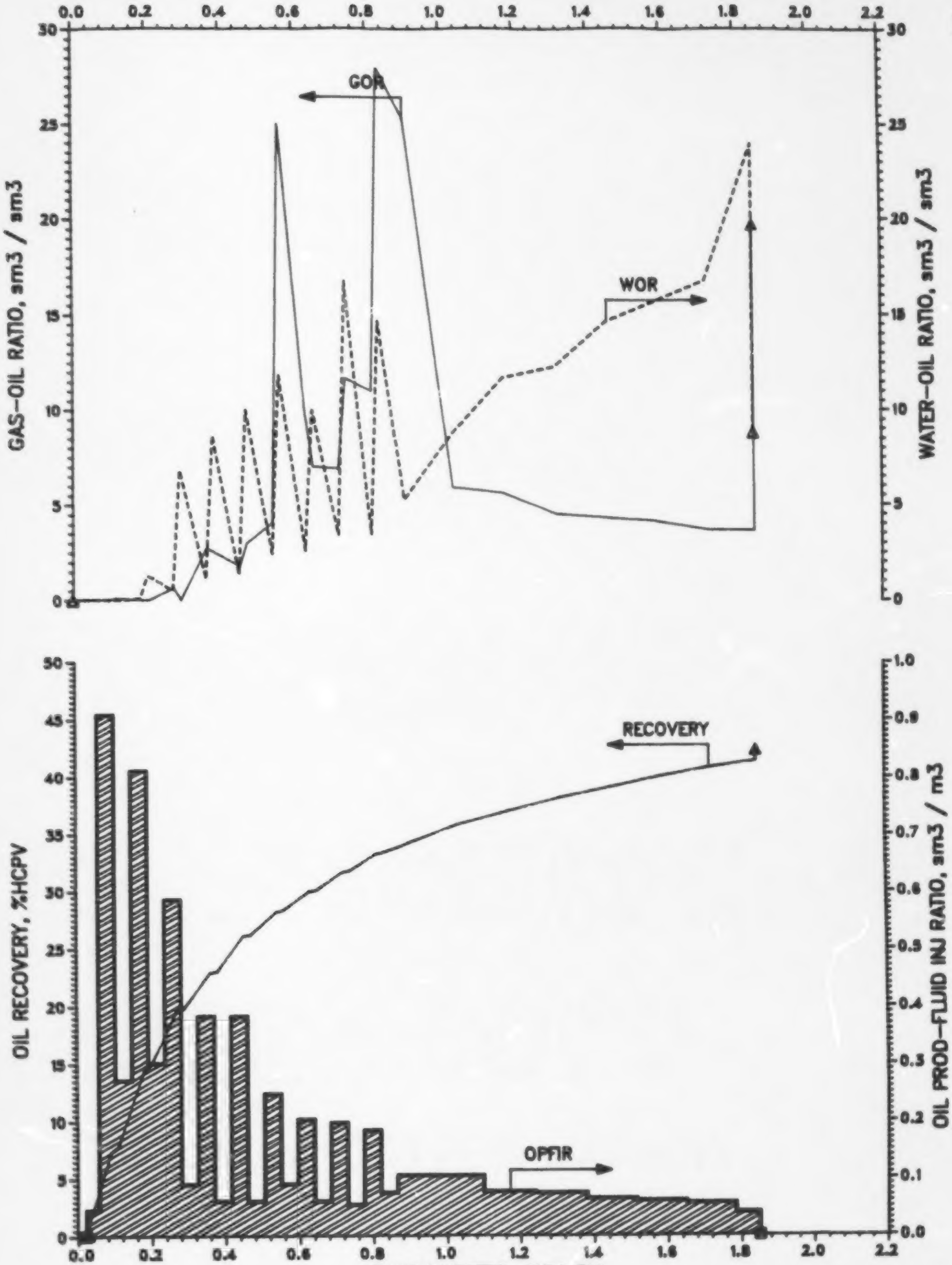
Figure 5.64 – Production History of Run 2DT3.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 37.16 %, k = 12.790 darcies, S_o = 90.14 %, S_{wc} = 9.86 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.139 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 20.00%

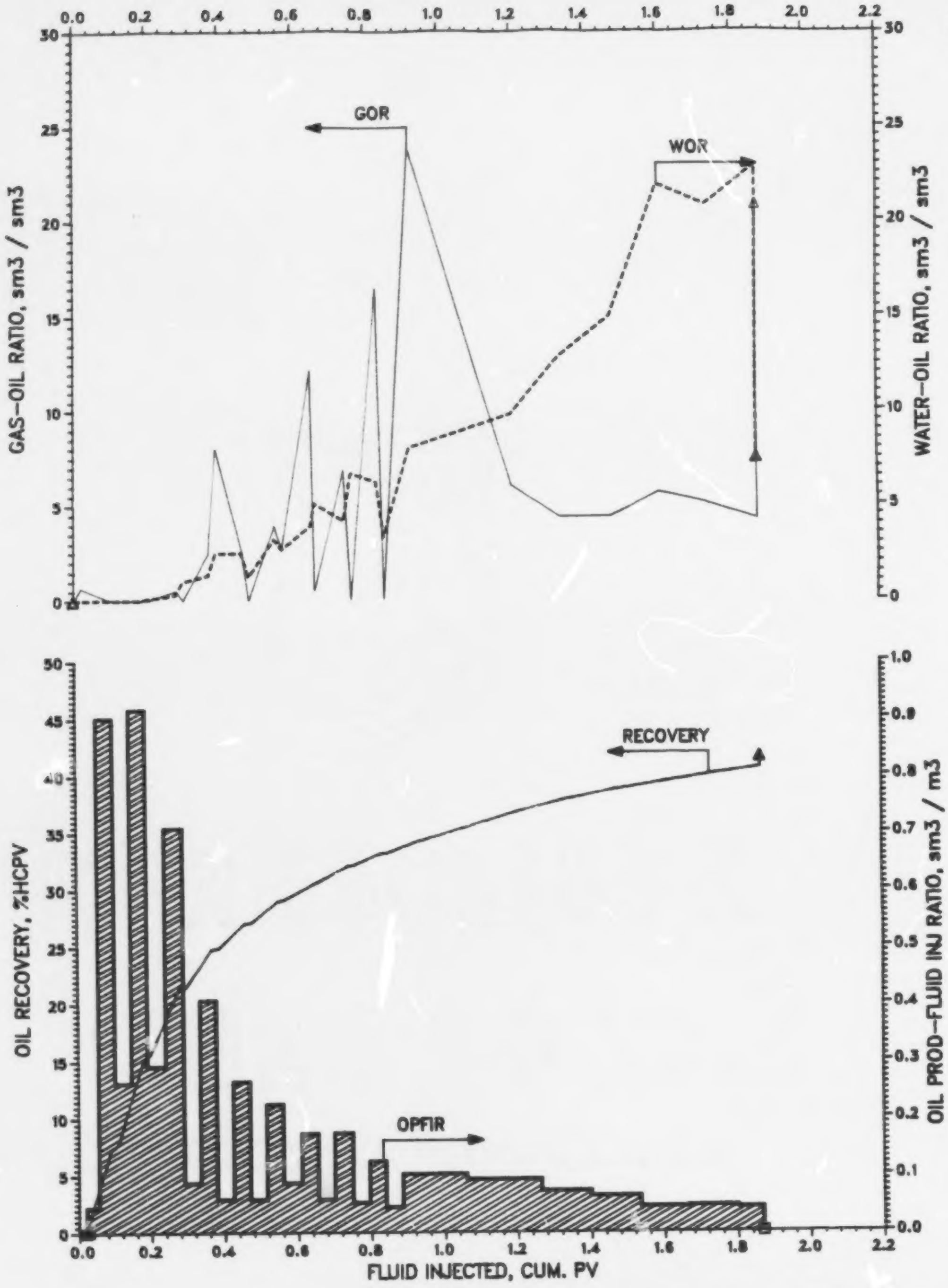
Figure 5.65 – Production History of Run 2DT4.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 38.00 %, k = 14.040 darcies, S_o = 89.95 %, S_{wc} = 10.05 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.142 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 25.00%

Figure 5.66 – Production History of Run 2DT5.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 38.25 %, k = 12.960 darcies, S_o = 92.30 %, S_{wc} = 7.70 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.146 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 30.00%

Figure 5.67 – Production History of Run 2DT6.

Figure 5.68 compares the producing GOR's of the two-dimensional model Runs 2DT1, 2DT3, and 2DT5 with that of Run GTD6[11]. As was observed in Section 5.3.2.1, the producing GOR increased with increasing nitrogen concentration in the mixture. Explanations for this phenomenon were given in Section 5.3.2.1

Figure 5.69 shows plots of the cumulative producing WOR versus the cumulative oil recovery. An examination of the curves in the figure reveals interesting features. In the beginning, all runs had nearly identical recovery at the same cumulative producing WOR. This was mainly because a very small volume of gas and water was injected at that time, and only the portion of oil near the production well had been produced. Subsequently, the recovery fell off and the cumulative producing WOR rose, depending on the volume of nitrogen present in the carbon dioxide stream. As shown, a larger volume of nitrogen in carbon dioxide corresponded to a higher cumulative producing WOR and a lower cumulative recovery.

The production of a large volume of water and a small volume of oil was the increased oil-to-water viscosity ratio (μ_o/μ_w), which was mainly caused from the decreased solubility and diffusivity of carbon dioxide into oil due to the presence of a non-condensible gas, i.e. nitrogen, as discussed in Sections 5.1 and 5.2. As a result, in the runs using carbon dioxide and a high concentration of nitrogen, water displaced less oil at a higher cumulative producing WOR. Thus, it can be expected that the fractional flow curve would shift to the left. The slope of the curve at low water saturations was larger and smaller at high water saturations for runs utilizing carbon dioxide containing a higher volume of nitrogen. Also, it is obvious that early water breakthrough could be observed since the fractional flow curve was steeper at lower water saturations. The water breakthrough occurred at 0.28 PV in Run 2DT1, at 0.27 PV in Run 2DT2, at 0.26 in Run 2DT3, at 0.20 PV in Run 2DT4, at 0.18 PV in Run 2DT5, and at 0.18 PV in Run 2DT6. Consequently, the limiting 20:1 WOR was reached earlier in runs employing carbon dioxide containing a higher concentration of nitrogen; also, loss of oil recovery and a shorter flood life were the result.

Summarizing, depending on the volume of nitrogen present in the carbon dioxide stream, the mobility ratio became more unfavourable. In particular, when the concentration of nitrogen was 15.0 to 30.0 mole%, the displacement became unstable, leading to a low sweep efficiency.

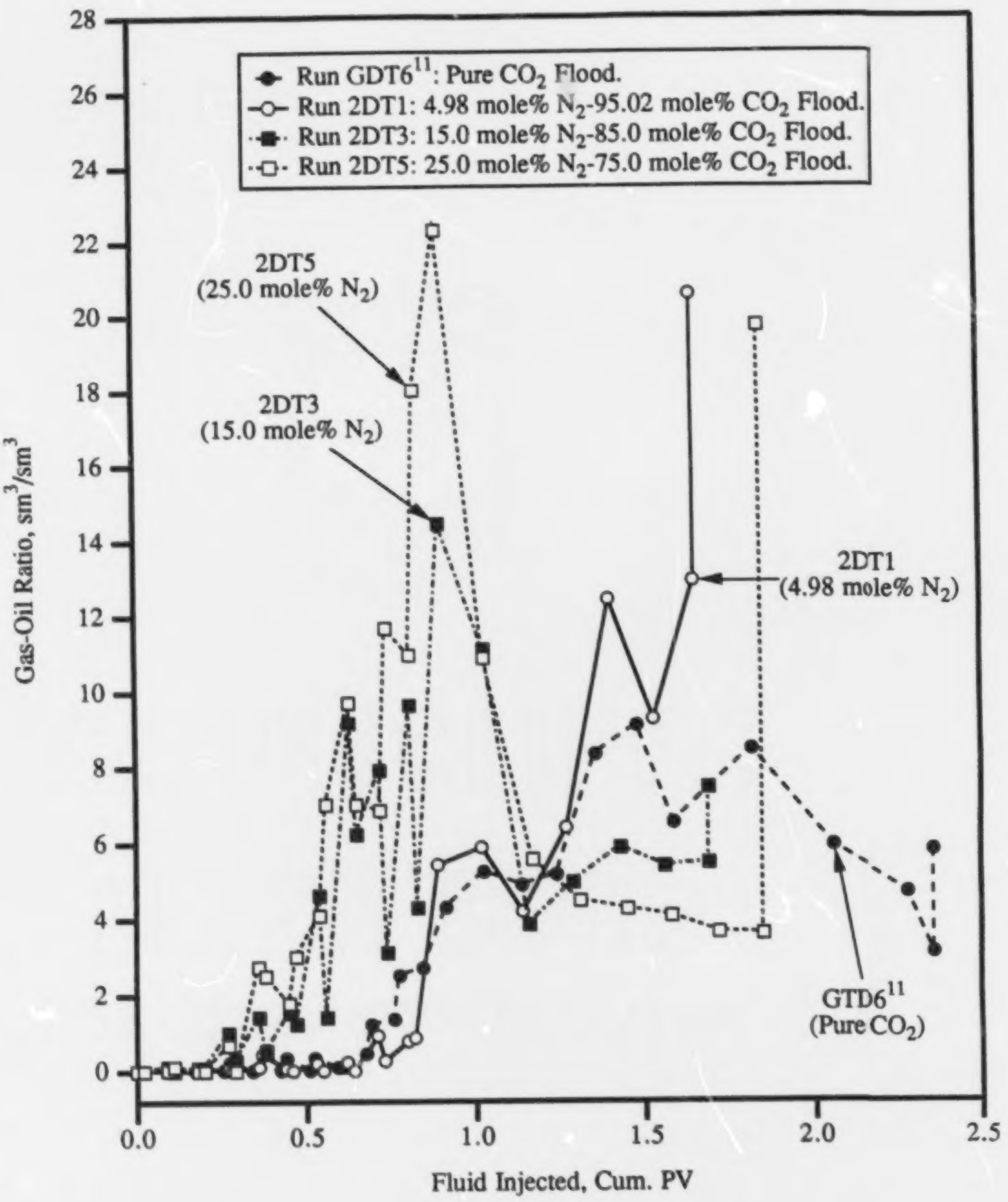


Figure 5.68 - Effect of Nitrogen on Producing GOR's (Two-Dimensional Model).

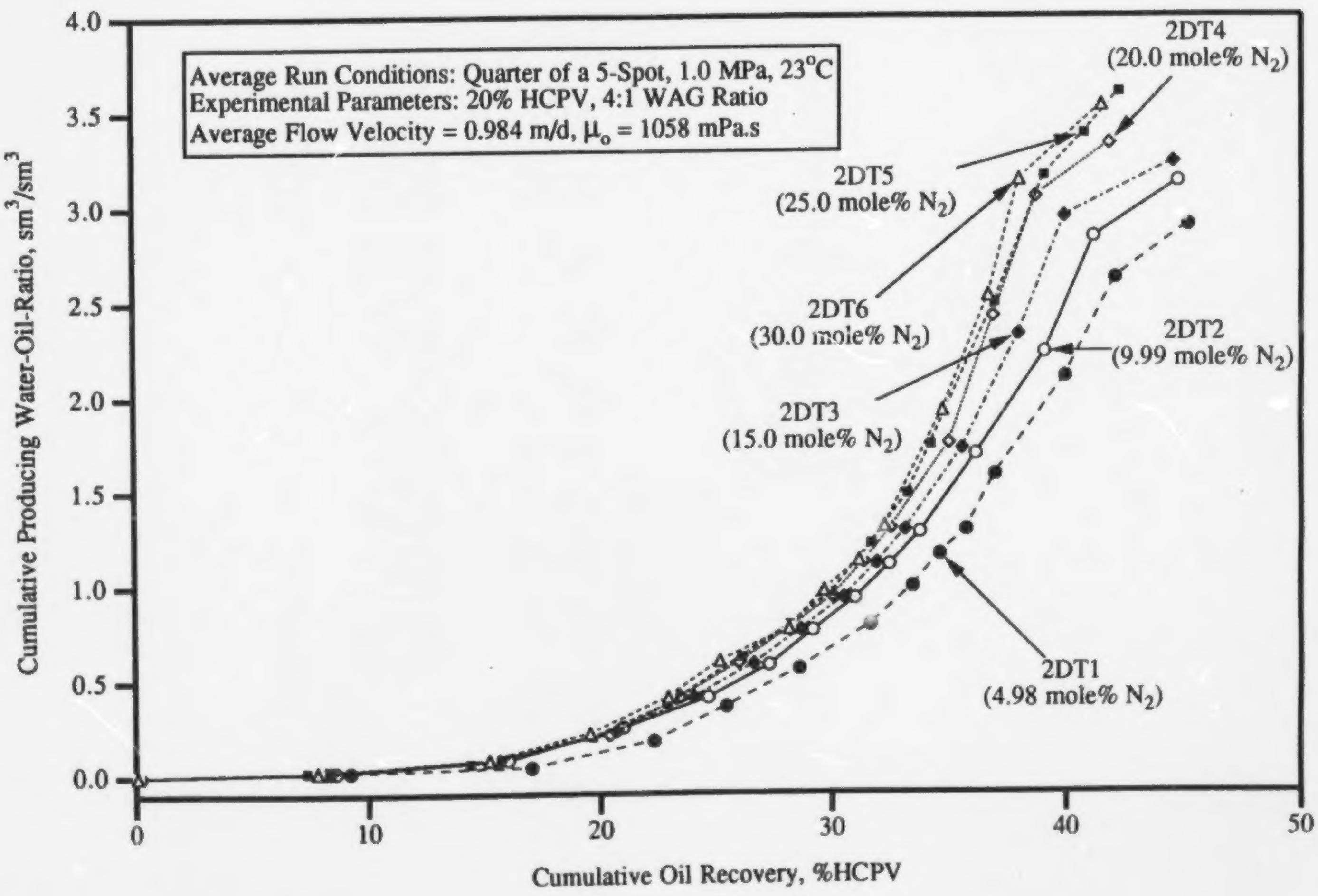


Figure 5.69 - Effect of Nitrogen on Displacement Efficiency.

5.3.2.10 Effect of Nitrogen on Carbon Dioxide Retention

Carbon dioxide retention depends on the amount of carbon dioxide left behind at the end of the flood. This carbon dioxide is largely dissolved in the oil left in the reservoir, and depends on the solution and diffusion of carbon dioxide into oil. From the results obtained, it is seen (Figure 5.70) that carbon dioxide retention decreased with an increase in the amount of nitrogen in the mixture since the solubility of the carbon dioxide mixture decreases due to the presence of nitrogen. The same phenomena was also observed for the linear model runs. Table 5.4a shows the carbon dioxide retention values for the linear model runs.

5.3.2.11 Effect of Nitrogen on Carbon Dioxide Requirement

Nitrogen (Figure 5.71) increased the amount of carbon dioxide required to produce a unit volume of oil. This is so because carbon dioxide tends to bypass the oil in the presence of nitrogen. As more gas bypassed the oil, more gas was required to produce a unit volume of oil. Similarly, the increased carbon dioxide requirement due to the presence of nitrogen was also noted in the linear model runs. Table 5.4a presents the carbon dioxide requirements for the linear model runs.

5.3.2.12 Effect of Carbon Dioxide Partial Pressure

Three two-dimensional model runs, 2DT8, 2DT9, and 2DT10, were done in the two-dimensional model to study the effect of carbon dioxide partial pressure. The gas mixtures used in the three runs contained 15.0, 20.0, and 30.0 mole% nitrogen, respectively. The operating pressures were 1.20, 1.25, and 1.44 MPa, respectively. Runs 2DT8 and 2DT10 were repeats of the linear model Runs 1DT14 and 1DT16, respectively. The detailed results of the experiments are included in Tables A39 to A41 (Appendix A).

In Run 2DT8, the oil recoveries in the WAG, post-waterflood, and blowdown phases were 38.37, 11.47, and 3.03%, respectively, giving a total recovery of 52.3%. In Run 2DT9, 45.97% of oil was recovered: 32.04, 11.42, and 2.51% in the WAG, post-waterflood, and blowdown phases, respectively. The total recovery for Run 2DT10 was 45.37%. The WAG recovery for this run was 31.72%, the post-waterflood recovery 11.08%, and the blowdown recovery was 2.57%. Figures 5.72 to 5.74 depict the recovery distributions of the experiments.

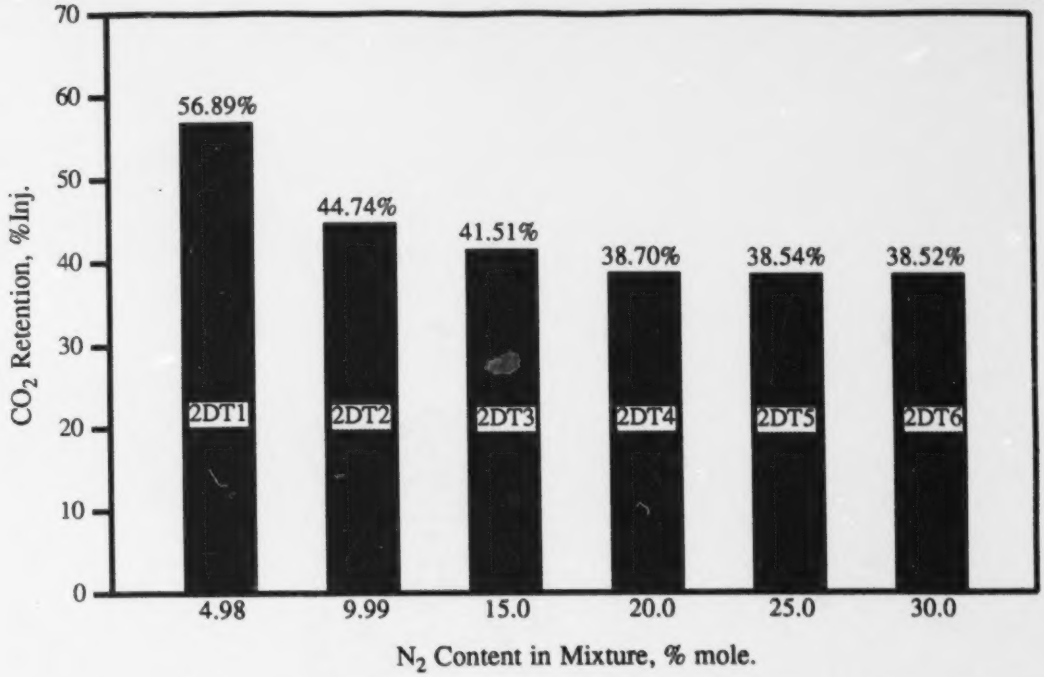


Figure 5.70 - Effect of Nitrogen on Carbon Dioxide Retention (Two-Dimensional Model Runs).

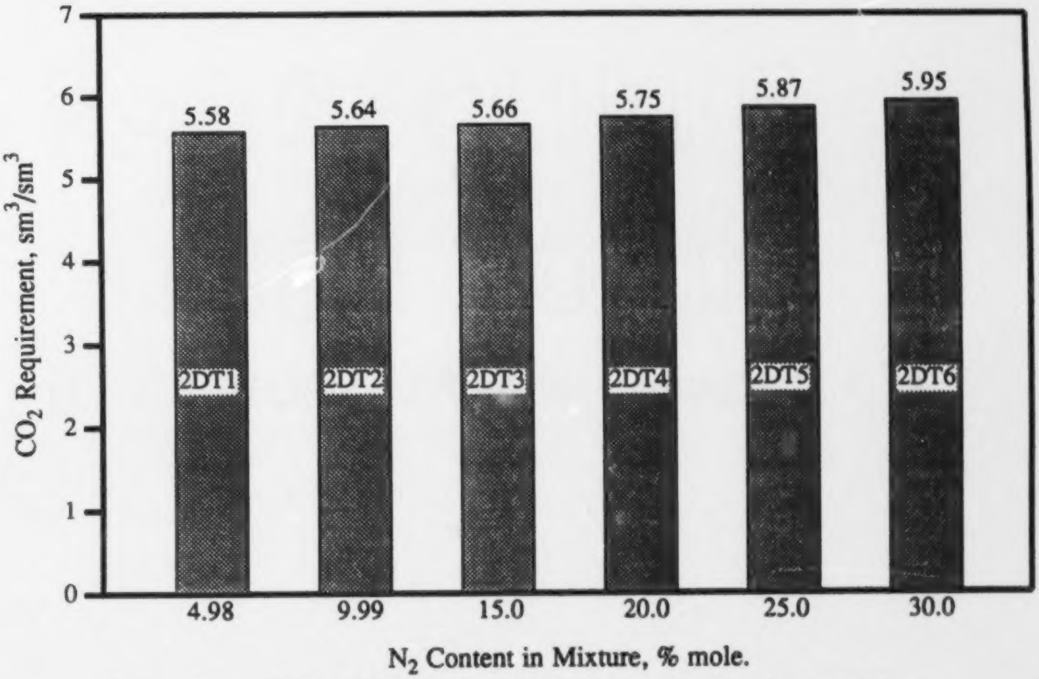
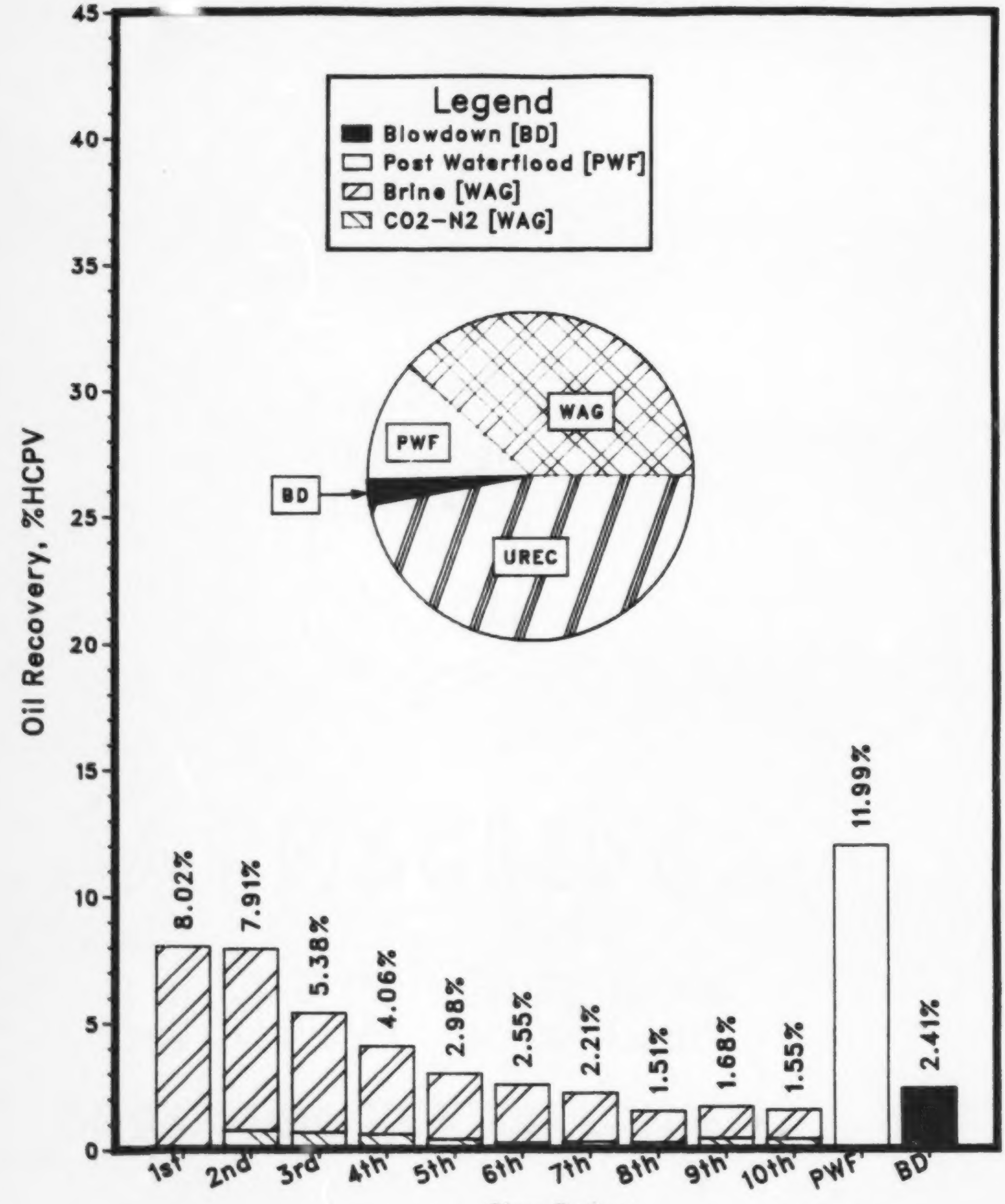


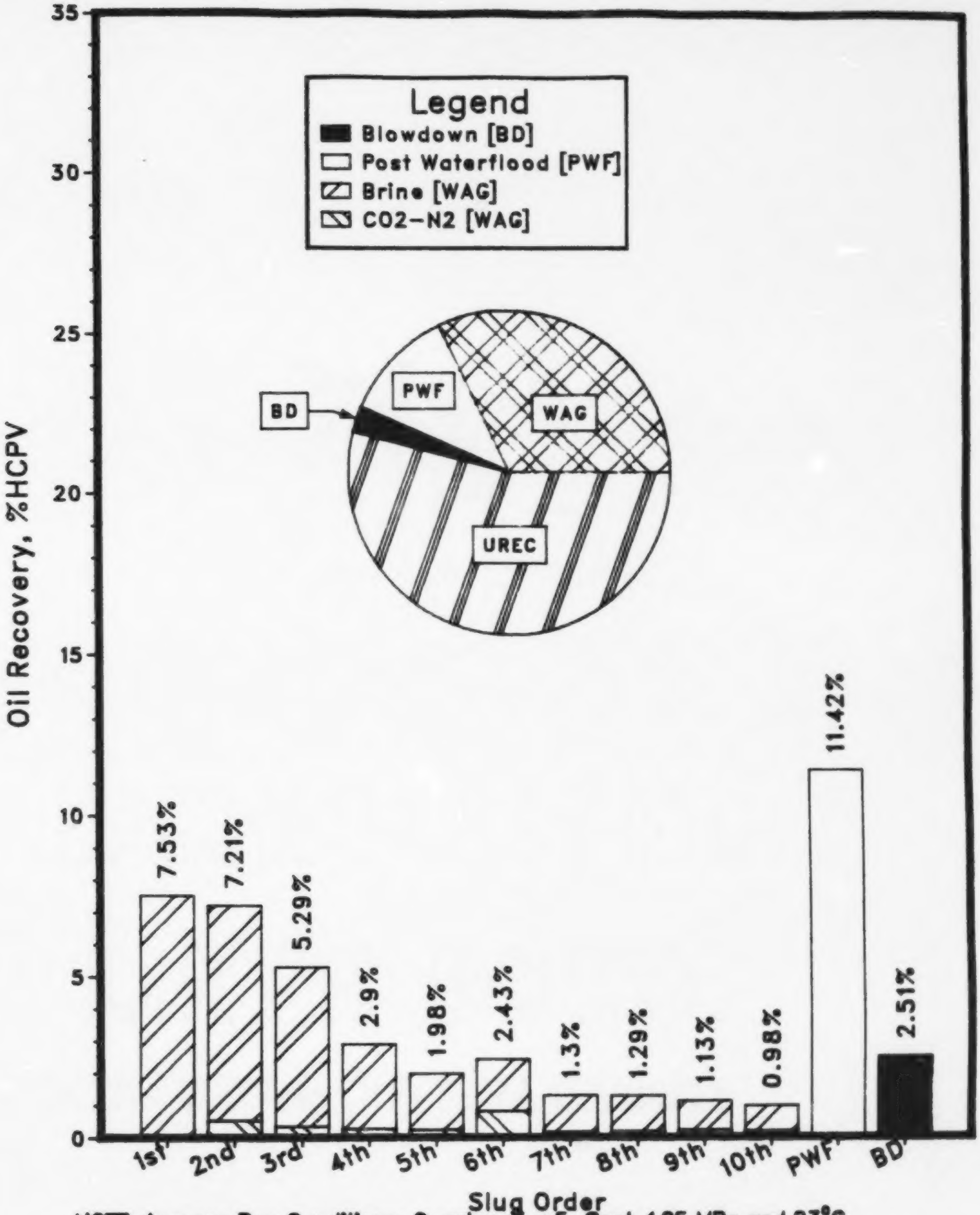
Figure 5.71 - Effect of Nitrogen on Carbon Dioxide Requirement (Two-Dimensional Model Runs).



NOTE: Average Run Conditions: Quarter of a 5-Spot, 1.20 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 37.71 %, k = 11.610 darcies, S_o = 88.11 %, S_{wc} = 11.89 %

[0.20 HCPV CO2-N2 @ 1.2 MPa (0.168 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]
Nitrogen Concentration in Mixture = 15.00%
Total Oil Recovery = 52.3% HCPV

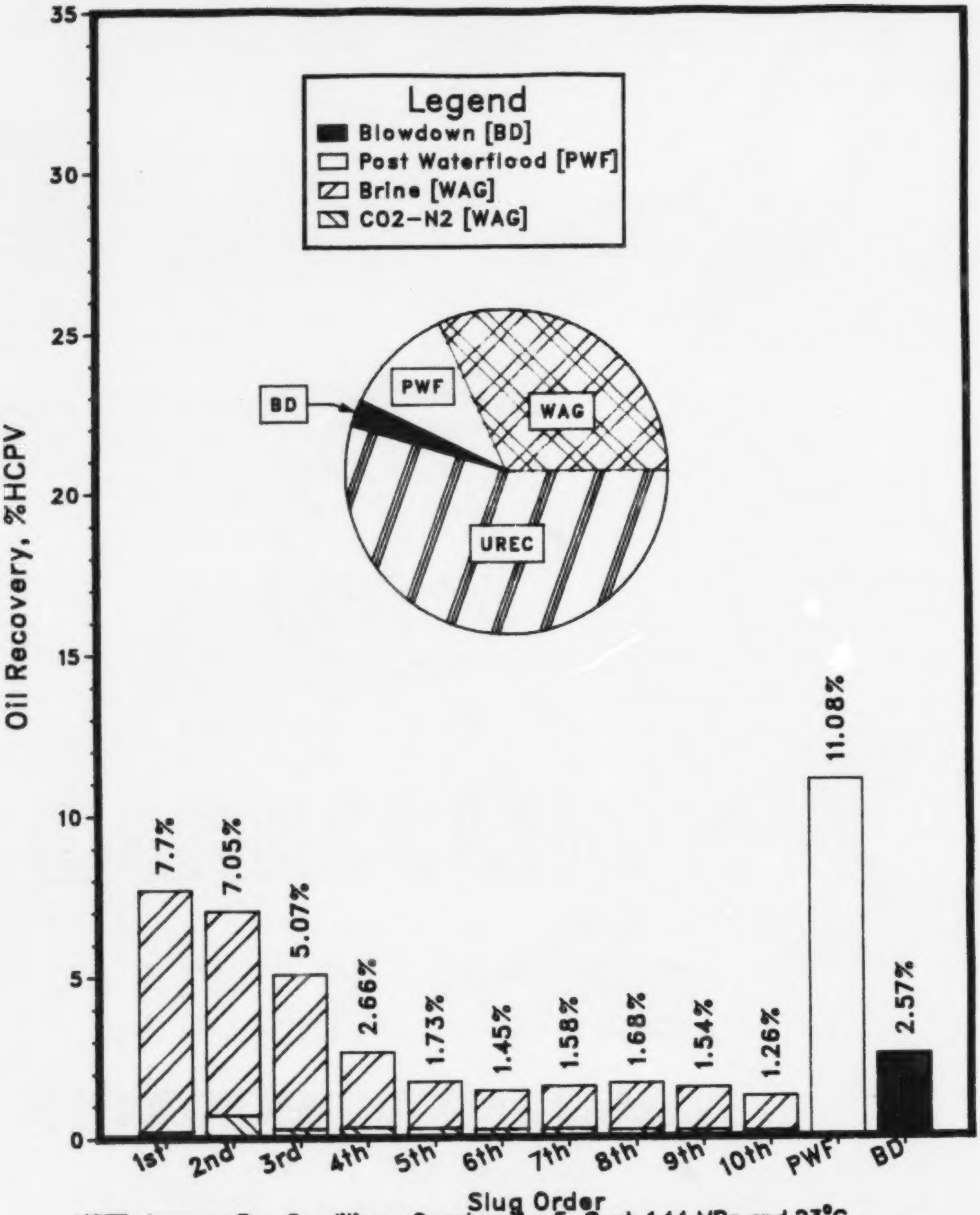
Figure 5.72 – Oil Recovery Distribution of Run 2DT8.



NOTE: Average Run Conditions: Quarter of a 5-Spot, 1.25 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 38.60 %, k = 12.960 darcies, S_o = 87.04 %, S_{wc} = 11.17 %

[0.20 HCPV CO2-N2 @ 1.25 MPa (0.176 g-mol) 4:1 WAG,10 Slugs,DEAD OIL]
N2 Concentration in Mixture = 20.00%
Total Oil Recovery = 46.0%

Figure 5.73 – Oil Recovery Distribution of Run 2DT9.



NOTE: Average Run Conditions: Quarter of a 5−Spot, 1.44 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 38.80 %, k = 11.400 darcies, S_o = 88.60 %, S_{wc} = 11.91 %

[0.20 HCPV CO2−N2 @ 1.44 MPa (0.208 g−mol) 4:1 WAG,10 Slugs,DEAD OIL]
N2 Concentration in Mixture = 30.00%
Total Oil Recovery = 45.4%

Figure 5.74 − Oil Recovery Distribution of Run 2DT10.

As noted above, Runs 1DT14 to 1DT16 and Runs 2DT8 to 2DT10 were similar, and were also compared with Run GTD6 which was conducted using pure carbon dioxide and at the same experimental parameters and conditions. Figure 5.75 shows the comparisons. Again, as was noted before, Run 2DT8 produced more oil than Run GTD6, while Runs 2DT9 and 2DT10 produced less oil. The previous explanation of Section 5.3.2.5 is applicable here also.

5.3.3 Reproducibility of The Experimental Results

An important aspect of this study concerns the reproducibility of the experimental results. Based upon the consistent trends, it is believed that the reproducibility of the experimental results was good.

Repeatability of the experiments was examined further by conducting Runs 1DT23, 1DT24, 2DT7 to check the reproducibility of the results obtained for Runs 1DT9, 1DT22, and 2DT1, respectively. Tables A23, A24, and A39 (Appendix A) contain the results of these three runs. The three pairs of runs had identical operating conditions: pressure, temperature, total gas slug size, flow velocity, gas mixture, and WAG ratio. The production histories of Runs 1DT23, 1DT24, and 2DT7 were plotted and compared with those of Runs 1DT9, 1DT22, and 2DT1, respectively, in Figures 5.76 to 5.78.

Figures 5.76 to 5.78 show that the reproducibility of the production history was good. It can be seen that the reproducibilities of the total recovery were 0.2, 0.3. and 0.2 %HCPV for runs 1DT1, 1DT22 and 2DT1, respectively. Rojas[5] also reported the reproducibilities of the total oil recovery within 0.3% HCPV and 1% HCPV. These discrepancies are in the normal experimental errors.

5.3.4 Comparison of Linear and Two-Dimensional Model Experiments

Figures 5.79 to 5.81 depict the comparisons of the producing GOR, WOR and production history of Run 1DT1 (linear model) with those of Run 2DT1 (two-dimensional model). Figure 5.79 shows that more gas was produced in the linear model Run 1DT1 than in the two-dimensional model Run 2DT1. A possible explanation for this higher volume of gas produced in Run 1DT1 is that more oil was produced in this run, as shown in Figure 5.81. The higher oil recovery obtained in the linear model Run 1DT1 was

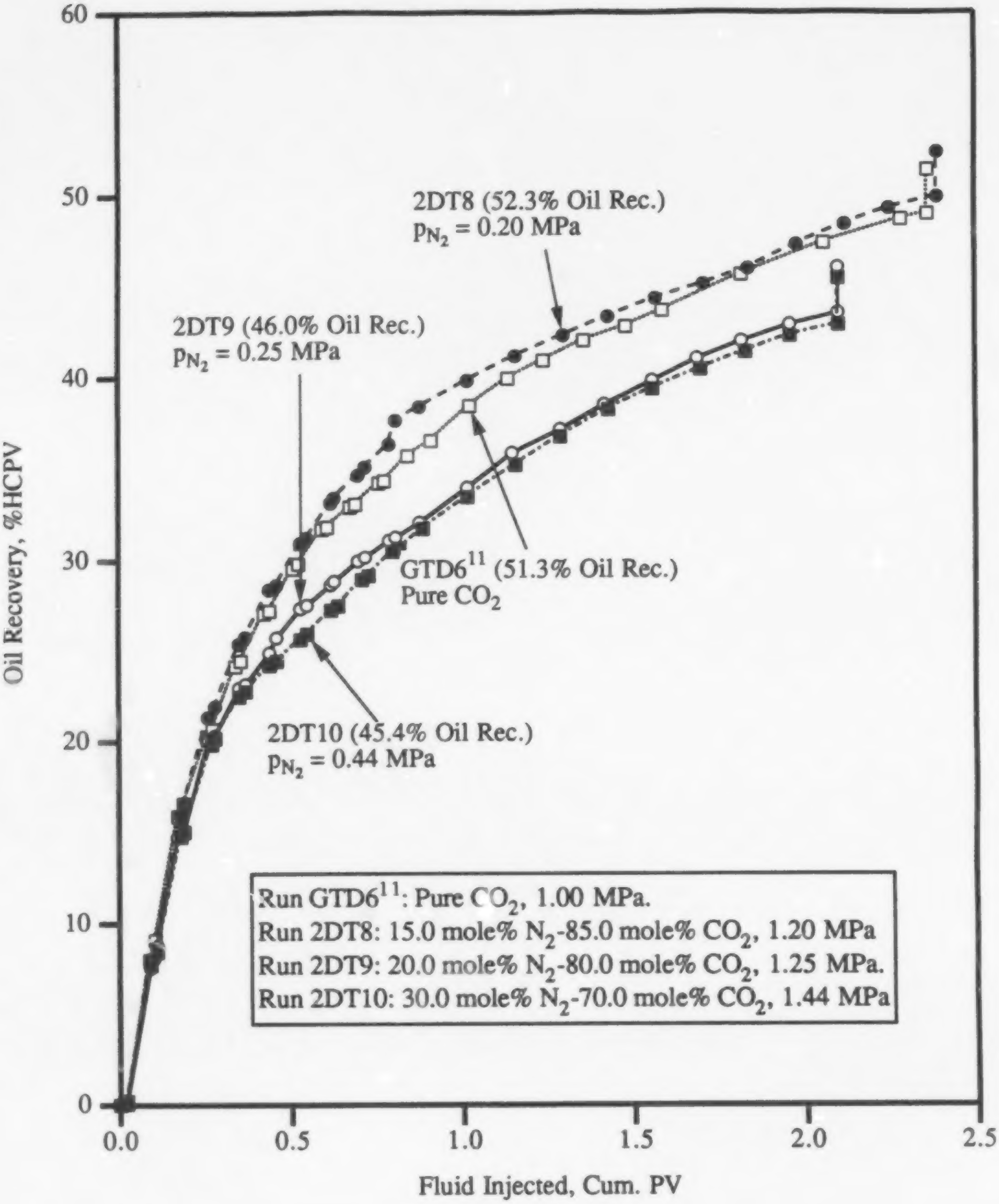


Figure 5.75 - Comparison of Runs 2DT8 - 2DT10 with Run GTD6.

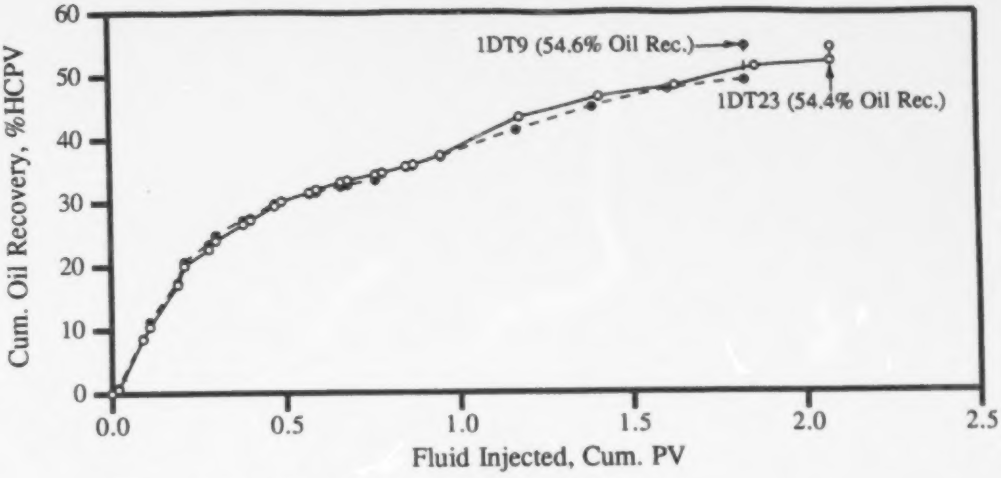


Figure 5.76 - Reproducibility of Run 1DT9.

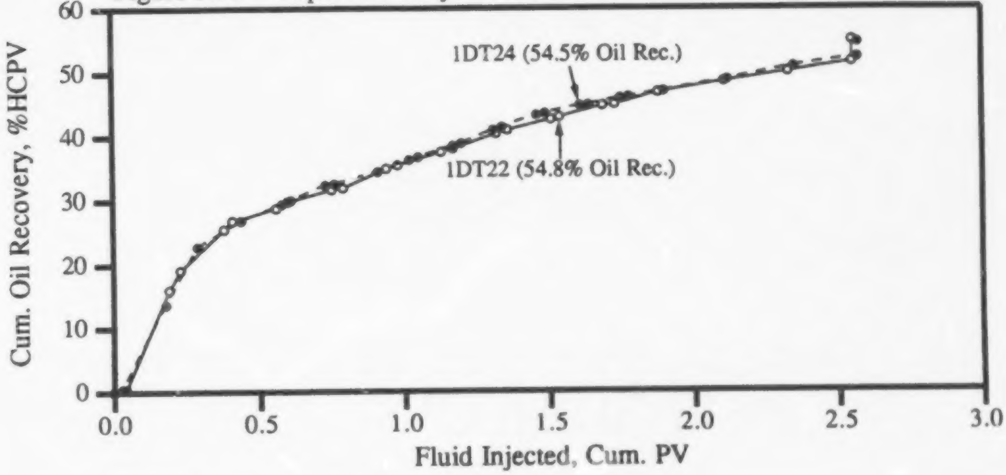


Figure 5.77 - Reproducibility of Run 1DT22.

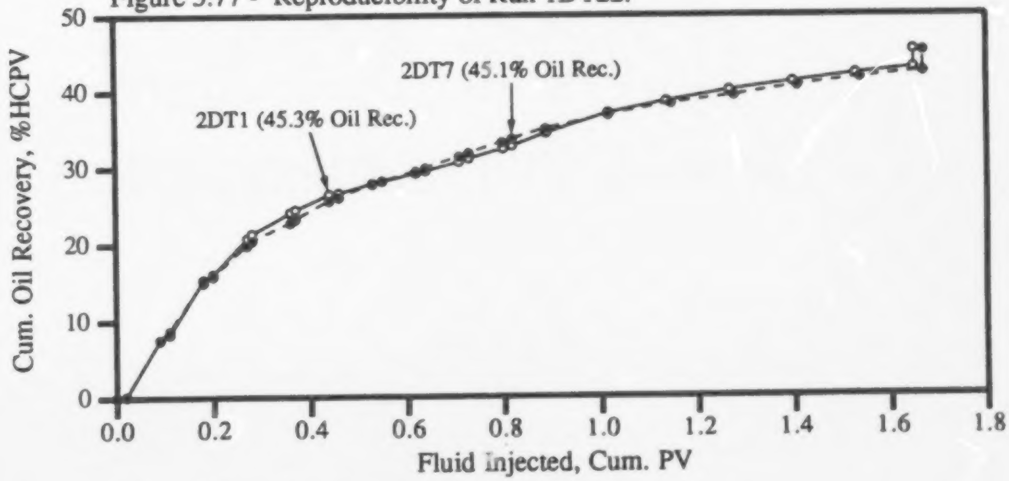


Figure 5.78 - Reproducibility of Run 2DT1.

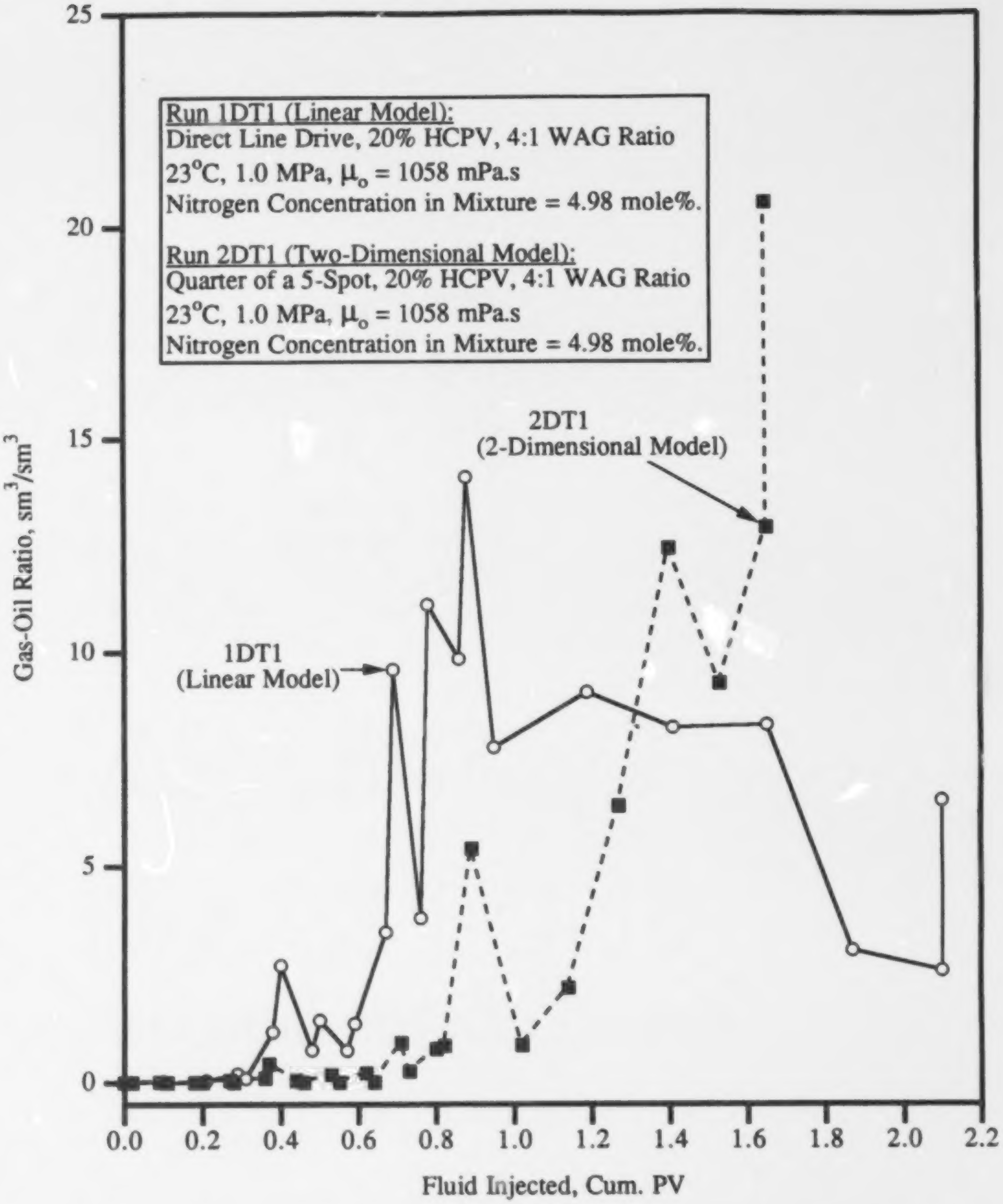


Figure 5.79 - Comparison of Producing GOR of a Linear and a Two-Dimensional Model Run.

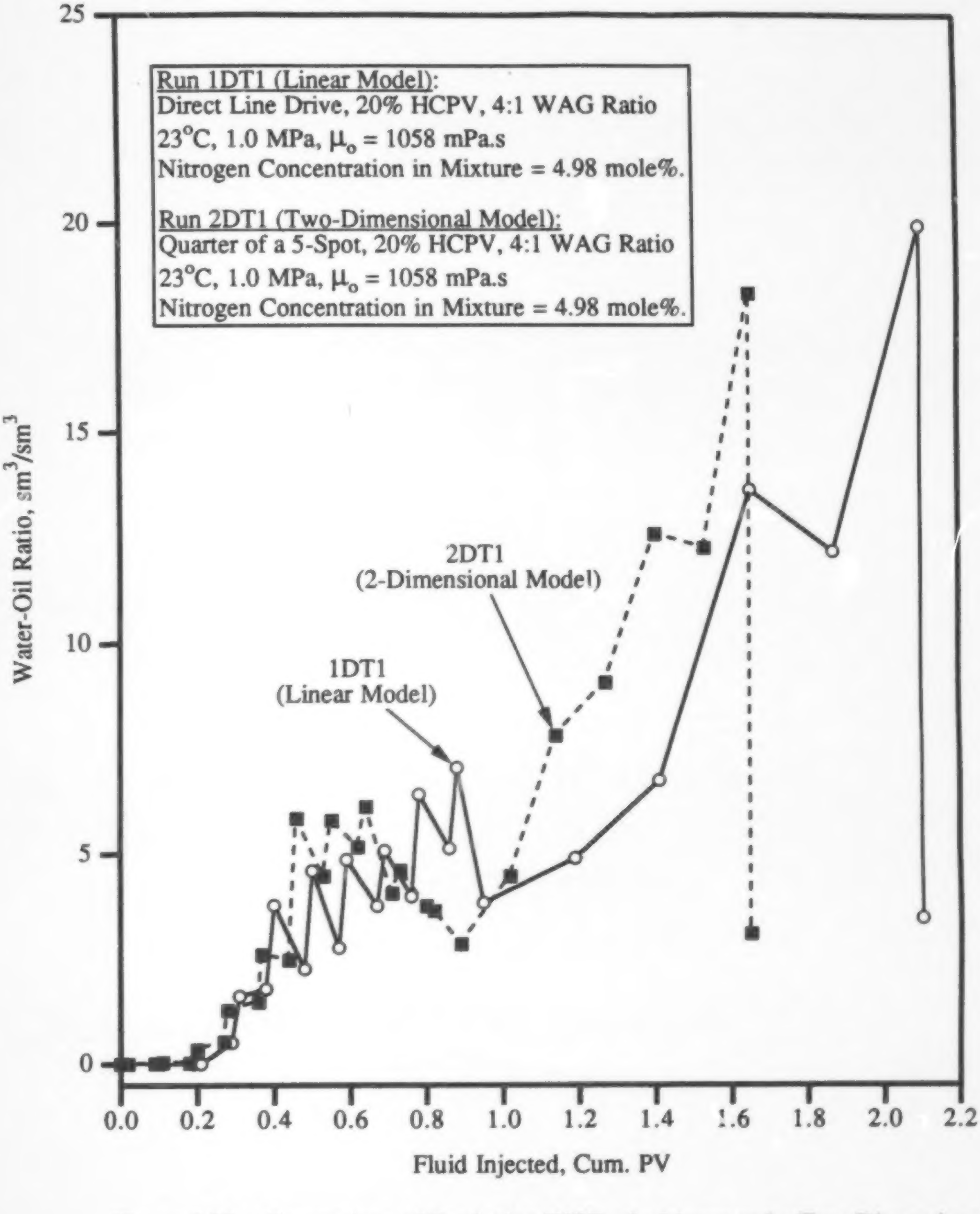
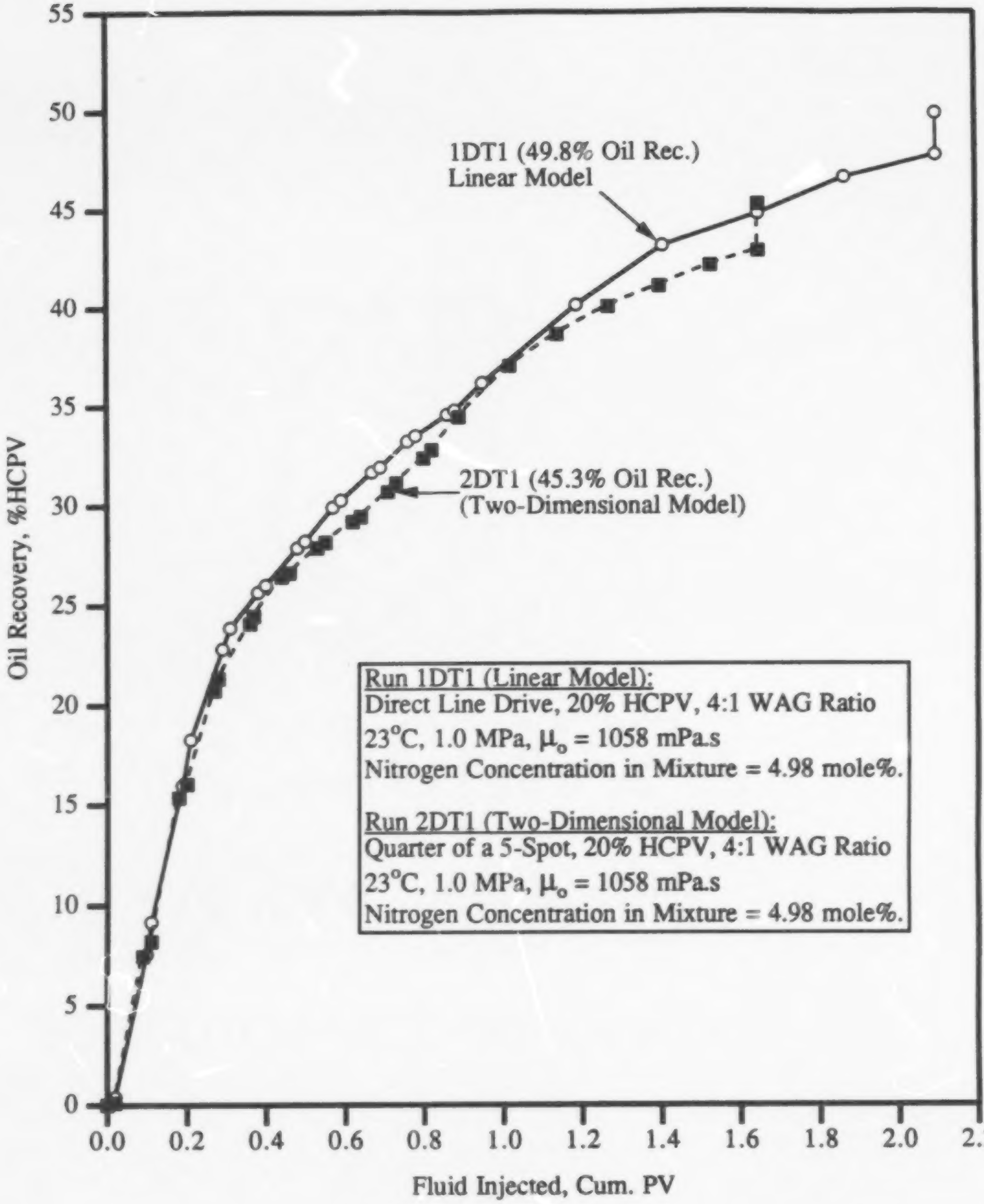


Figure 5.80 - Comparison of Producing WOR of a Linear and a Two-Dimensional Model Run.



Run 1DT1 (Linear Model):
Direct Line Drive, 20% HCPV, 4:1 WAG Ratio
23°C, 1.0 MPa, μ_o = 1058 mPa.s
Nitrogen Concentration in Mixture = 4.98 mole%.

Run 2DT1 (Two-Dimensional Model):
Quarter of a 5-Spot, 20% HCPV, 4:1 WAG Ratio
23°C, 1.0 MPa, μ_o = 1058 mPa.s
Nitrogen Concentration in Mixture = 4.98 mole%.

Figure 5.81 - Comparison of Oil Recovery of a Linear and a Two-Dimensional Model Run.

probably due to the 100% sweep efficiency in the linear model. This is clearly shown in Figure 5.80. More water was produced in the two-dimensional model Run 2DT1 than in the linear model Run 1DT1. The difference in flow pattern (linear flow in the linear model vs. flow in the two-dimensional model) is thought to contribute to the difference in sweep efficiency and thus oil recovery.

Also, the diffusion and dispersion of gas in the two-dimensional model were two-dimensional while they are confined to one dimension in the linear model. It is difficult to say in which model the diffusion and dispersion of gas were higher; probably the longitudinal diffusion and dispersion in the linear model were higher than those in the two-dimensional model.

5.3.5 Comparison of This Study With Previous Studies

The purpose of this section is to compare the two-dimensional model results obtained in this study with those obtained in the previous studies that employed pure carbon dioxide (and nitrogen in a few cases) to determine to what extent the presence of nitrogen in the injected carbon dioxide has an adverse effect on oil recovery.

5.3.5.1 Comparison of Nitrogen-Carbon Dioxide Runs With Those Conducted With an Initial Nitrogen Saturation

Comparisons of Runs 2DT1 and 2DT3 conducted with 4.98 and 15.0 mole% nitrogen mixtures at 1.0 MPa, respectively, with Runs 32Z[8] and 30Z[8] conducted with initial nitrogen gas saturations of 4.0% and 15.3% at 2.5 MPa, respectively, were made and are shown in Figures 5.82 to 5.85.

In Figure 5.82, the higher trend of the producing GOR curve of Run 32Z[8] compared to that of Run 2DT1 indicates that the presence of an initial nitrogen gas saturation caused an increase in the carbon dioxide mobility and the immediate production of gas. The gas breakthrough took place at 0.033 PV, which was right at the very start of the injection of the very first carbon dioxide slug. This shows that the presence of a nitrogen gas phase substantially increased the mobility and relative permeability to the gas phase. It is instructive to look at the way in which nitrogen and carbon dioxide were used. In Run 2DT1, a 4.98 mole% nitrogen-95.02 mole% carbon dioxide mixture was used. This means that nitrogen and carbon dioxide were mixed with each other, which also implies that carbon dioxide helped to reduce the mobility of nitrogen. Whereas, in Run

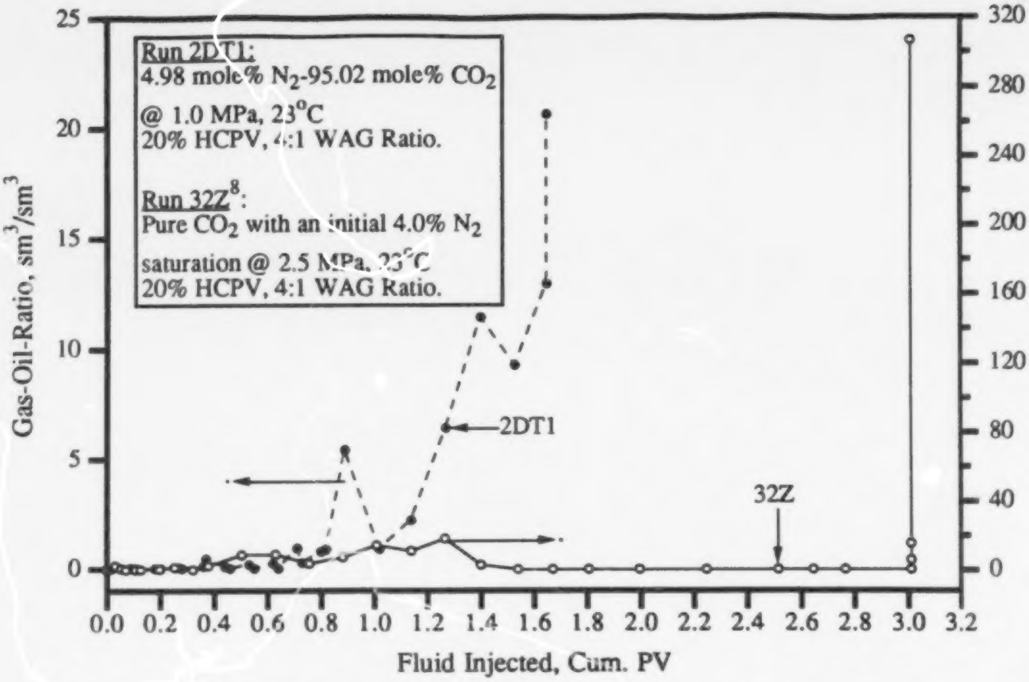


Figure 5.82 - Comparison of Producing GOR's of Runs 2DT1 and 32Z Utilizing an Initial 4.0% Nitrogen Saturation.

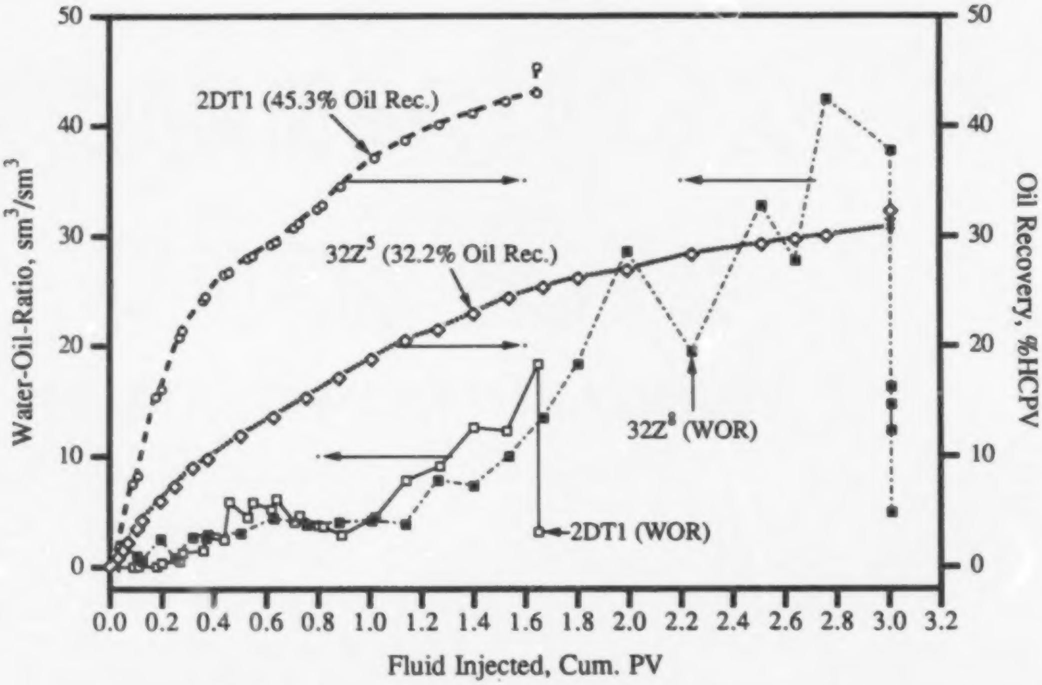


Figure 5.83 - Comparison of Producing WOR's and Recoveries of Runs 2DT1and 32Z Utilizing an Intitial 4.0% Nitrogen Saturation.

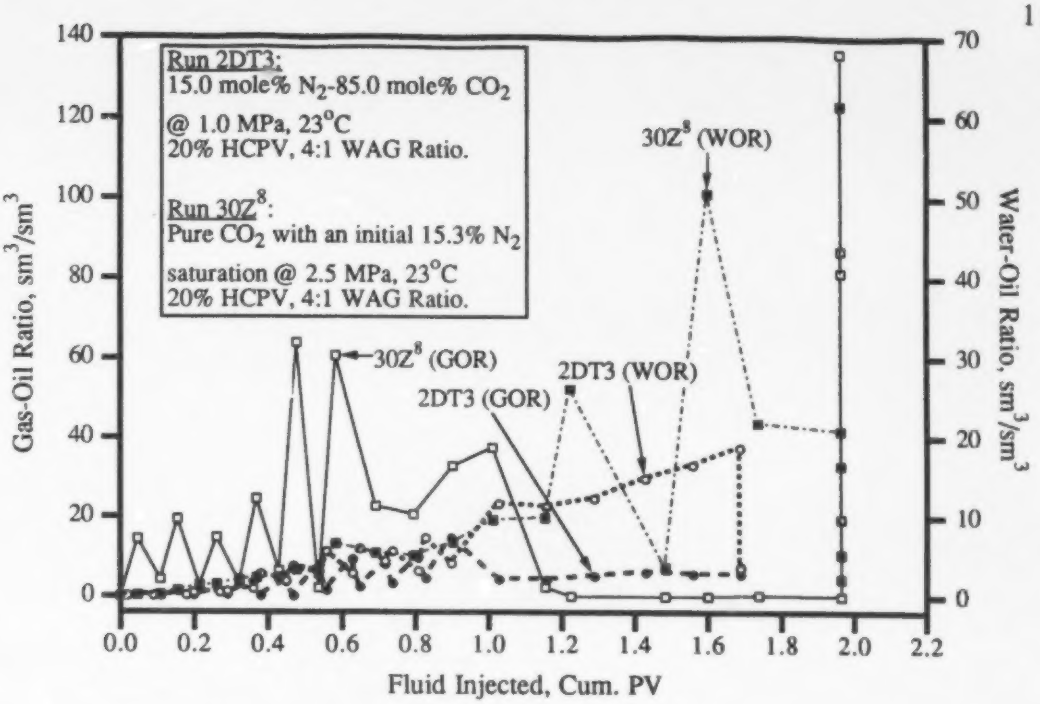


Figure 5.84 - Comparison of Producing GOR's and WOR's of Runs 2DT3 and 30Z Utilizing an Intial 15.3% Nitrogen Saturation.

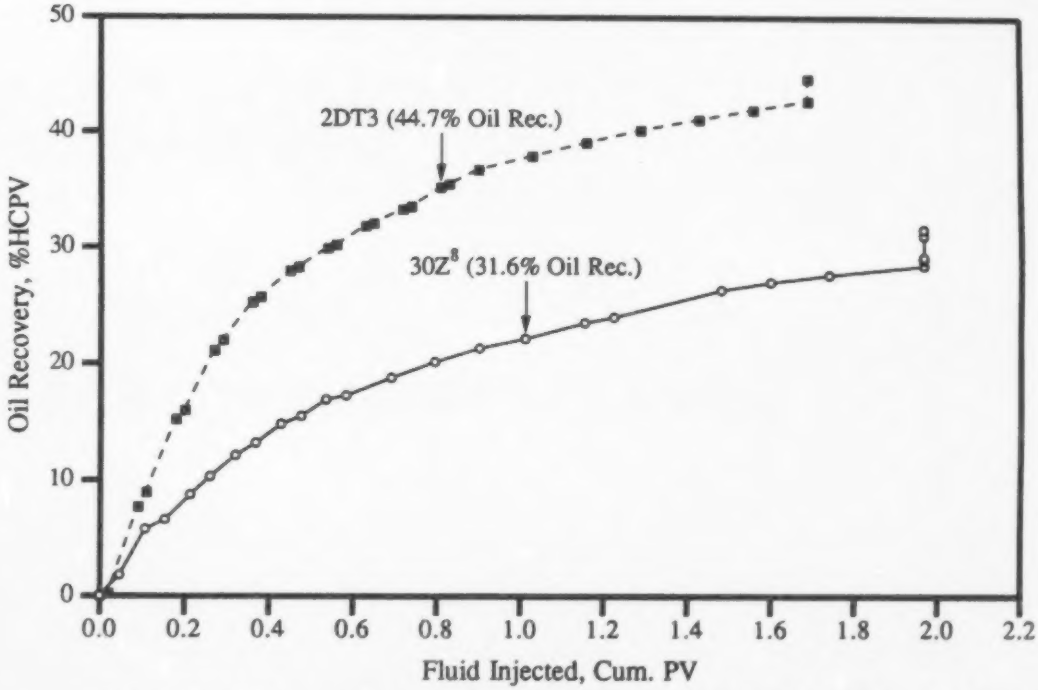


Figure 5.85 - Comparison of Recoveries of Runs 2DT3 and 30Z Utilizing an Initial 15.3% Nitrogen Saturation.

32Z[8], nitrogen and carbon dioxide were not mixed, and initially, there was only nitrogen gas in the model. When carbon dioxide was injected, it diffused through the nitrogen gas, resulting in the production of gas at the very start of the flood. After some carbon dioxide had been injected, there were two separate gas regions - nitrogen and carbon dioxide, i.e., the nitrogen region was in front of the carbon dioxide region. Since nitrogen is known as a non-condensible gas, it was instrumental in causing channelling of carbon dioxide also, with less carbon dioxide diffusing into oil. This is why the producing GOR curve of Run 32Z[8] is higher than that of Run 2DT1. Because of this, in Run 32Z[8], water had to displace a more viscous oil at high producing WOR's. Only 32.2% of oil was recovered, as compared to 45.3% oil recovery in Run 2DT1 and at much lower producing WOR's. Similar features can be observed in Figures 5.84 and 5.85, where a comparison of Run 2DT3 is made with Run 30Z[8].

Comparing the 32.2% and 31.6% recoveries respectively obtained in Runs 32Z[8] and 30Z[8] with the 32.4% recovery obtained in Run 11R[5] by waterflood shows that the immiscible carbon dioxide WAG process, with an initial nitrogen gas phase present, is no more efficient than a waterflood. The oil recoveries by the two processes agree within 1%.

In conclusion, based on the above evidence, it is obvious that the use of a nitrogen-carbon dioxide mixture in place of pure carbon dioxide is more desirable than the use of pure carbon dioxide in the presence of an initial nitrogen gas saturation in the immiscible WAG process.

5.3.5.2 Comparison of Impure Carbon Dioxide Runs With Pure Carbon Dioxide and Nitrogen Runs

Runs 2DT1 to 2DT6 can be compared with runs GTD6[11] and 5Z[8], employing pure carbon dioxide and pure nitrogen, respectively. Figures 5.86 and 5.87 show these comparisons.

Figure 5.86 provides a comparison of the producing GOR's of Runs 2DT1, 2DT3, and 2DT5 with those of Runs GTD6[11] and 5Z[8]. The observations of Section 5.2.7.1 will apply to Run 5Z[8] also, e.g., the breakthrough of nitrogen gas took place immediately after injection and large volumes of nitrogen were produced during the experiment.

The loss of oil recovery due to the presence of nitrogen in carbon dioxide, and the maximum acceptable concentration of nitrogen can be speculated on the basis of Figure

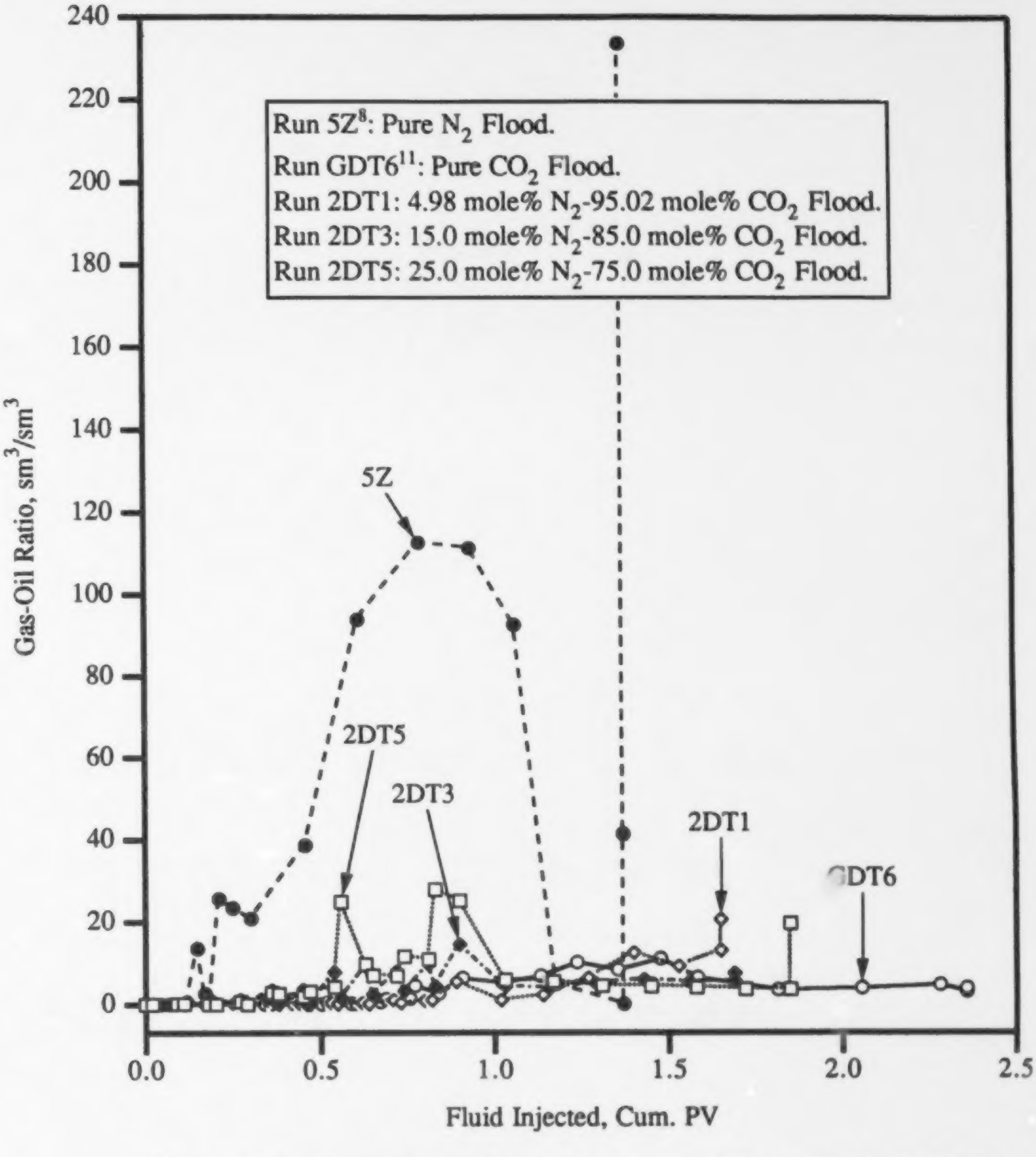


Figure 5.86 - Comparison of Producing GOR's of Runs GTD6, 5Z, 2DT1, 2DT3, and 2DT5.

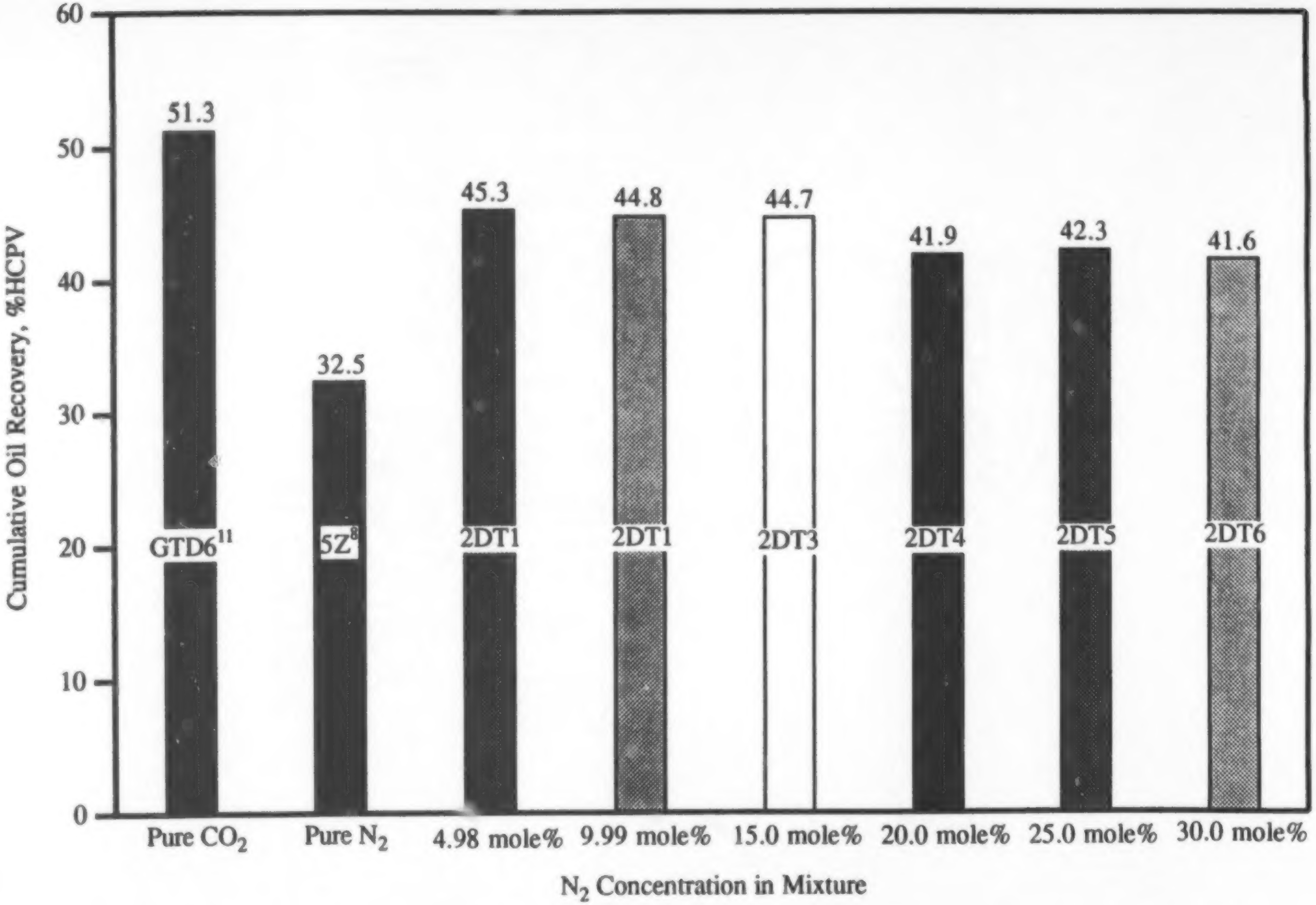


Figure 5.87 - Comparison of Carbon Dioxide-Nitrogen Runs With Pure Carbon Dioxide and Pure Nitrogen Runs.

5.87, where the cumulative oil recoveries of Runs GTD6[11], 5Z[8], and 2DT1-2DT6 are plotted. The use of pure nitrogen in the immiscible WAG mode (Run 5Z[8]) produced the least recovery, only 32.5%, which is very close to the waterflood recovery (32.4%[5]). Considering the 45.3, 44.8, and 44.7% recoveries obtained in Runs 2DT1 (4.98 mole% nitrogen-95.02 mole% carbon dioxide), 2DT2 (9.99 mole% nitrogen-90.01 mole% carbon dioxide), and 2DT3 (15.0 mole% nitrogen-85.0 mole% carbon dioxide), respectively, there is virtually no difference in oil recovery for the use of carbon dioxide containing 5.0 to 15.0 mole% nitrogen. A similar conclusion can be reached when observing the recoveries of Runs 2DT4 to 2DT6.

As mentioned earlier, the maximum volume of nitrogen that can be allowed in carbon dioxide to make the immiscible WAG process effective for field application is the most important since sources of pure carbon dioxide are very rare in the field. A comparison of the cumulative recoveries of Runs 2DT1 to 2DT6 with that of Run GTD6 will help to determine the maximum acceptable concentration of nitrogen. As shown in Figure 5.87, a recovery loss of 6.0 percent occurred when impure carbon dioxide gas containing up to 15.0 mole% nitrogen was used, while a recovery loss of 10.0 percent was incurred when impure carbon dioxide gas containing up to 30.0 mole% nitrogen was utilized. Therefore, to avoid a substantial loss of recovery, the maximum allowable concentration of nitrogen is 15.0 mole%. If carbon dioxide contains a very small amount of nitrogen, e.g. 1-3 mole%, the performance would be close to that of pure carbon dioxide.

5.3.6 Scale-up of the Experimental Results

This section concerns the prediction of the field performance of the immiscible WAG process and the implications of the experimental results for field application.

The scaling groups derived by Lozada and Farouq Ali[79] were used to scale up the experimental results to predict the field performance of the process. Keeping in view that the two-dimensional model was scaled to the field, it is appropriate to scale up the results of the two-dimensional model runs to predict the recovery performance of the field reservoir. The following calculations illustrate the procedure for scaling up the experimental results of Run GTD6[11] to the Aberfeldy field. The information on the field is given in Table 3.4.

5.3.6.1 Field Prediction of Injection Rate

The field carbon dioxide injection rate could be determined by the scaling group:

$$\left(\frac{W_g\mu_g}{h\Delta pk_g\rho_g}\right)_{Model} = \frac{1}{4}\left(\frac{W_g\mu_g}{h\Delta pk_g\rho_g}\right)_{Field}$$

Re-arrange to obtain

$$\left(\frac{W_g}{\rho_g}\right)_{Field} = 4\left(\frac{W_g}{\rho_g}\right)_{Model}\left(\frac{\mu_{g,Model}}{\mu_{g,Field}}\right)\left(\frac{(\Delta phk)_{Field}}{(\Delta phk)_{Model}}\right)$$

$$= 4\left(\frac{W_g}{\rho_g}\right)_{Model}\frac{(hk)_{Field}}{(hk)_{Model}}.$$

When scaling down the diffusive forces, Lozada and Farouq Ali[79] reduced the permeability by a factor "a", which is equal to field well spacing divided by lab well spacing. Also, the height of the field was reduced by "a" to determine the height of the model. Therefore, this equation becomes:

$$\left(\frac{W_g}{\rho_g}\right)_{Field} = 4\left(\frac{W_g}{\rho_g}\right)_{Model} a^2\frac{k_{Field}}{k_{Model}}.$$

Given that the model injection rate was

$$\left(\frac{W_g}{\rho_g}\right)_{Model} = 7.392\times10^{-3}\ \mathrm{m}^3/\mathrm{day\ at\ 1.0\ MPa.}$$

and knowing $k_{Field} = 1.0354$ d, $k_{Model} = 12.4$ d, and $a = 127.23\sqrt{2}/0.457\sqrt{2}$ $= 278.4$ led to:

$$\left(\frac{W_g}{\rho_g}\right)_{Field} = 4\times7.392\times10^{-3}\ \mathrm{m}^3/\mathrm{day}\times\frac{278.4^2\times1.0354\ \mathrm{d}}{12.4\ \mathrm{d}}$$

$$= 191.36\ \mathrm{m}^3/\mathrm{day\ at\ 1.0\ MPa.}$$

5.3.6.2 Field Prediction of Injection Time

The experimental carbon dioxide injection time can be scaled up by the group:

$$\left\{\frac{t_g\left(W_g/\rho_g\right)}{\phi h w^2}\right\}_{\text{Field}} = \left\{\frac{t_g\left(W_g/\rho_g\right)}{\phi h w^2}\right\}_{\text{Model}}$$

Re-arranging this equation gives

$$t_{g,\,\text{Field}} = \left\{\frac{t_g\left(W_g/\rho_g\right)}{\phi h w^2}\right\}_{\text{Model}} \left\{\frac{\left(W_g/\rho_g\right)}{\phi h w^2}\right\}_{\text{Field}}^{-1}$$

Knowing

$t_{g,\,\text{Model}} = 1.13$ hrs

$\phi_{\text{Model}} = 42.1\%$ $\qquad$ $\phi_{\text{Field}} = 35.0\%$

$w_{\text{Model}} = 0.457$ m $\qquad$ $w_{\text{Field}} = 254.46$ m

$h_{\text{Model}} = 0.022$ m $\qquad$ $h_{\text{Field}} = 6.1$ m

and the model and field carbon dioxide injection rates give:

$$t_{g,\text{Field}} = 4.5 \text{ months}$$

Similarly, the field water injection time can be predicted by the group

$$t_{w,\,\text{Field}} = t_{w,\,\text{Model}} \left(\frac{W_w/\rho_w}{\phi h w^2}\right)_{\text{Model}} \left(\frac{W_w/\rho_w}{\phi h w^2}\right)_{\text{Field}}^{-1}$$

Substituting numerical values gave:

$$t_{w,\,\text{Field}} = 79 \text{ months}$$

Note that the total water time included the water injection time in the post-waterflood phase.

The field total injection time becomes

$$t_{\text{total},\,\text{Field}} = \left(t_g + t_w\right)_{\text{Field}}$$

$$t_{\text{total},\,\text{Field}} = 7.0 \text{ years}$$

5.3.6.3 Field Prediction of Cumulative Production

According to Lozada and Farouq Ali[79], the cumulative total oil production can be scaled up based on the dimensions of the physical model since the production pressure was specified as a boundary condition, not the production rate, in deriving the scaling groups.

$$Q_{prod,\ Field} = \left\{\frac{Q_{prod}}{(1 - S_{wi})\phi hw^2}\right\}_{Model} \left\{\phi hw^2(1 - S_{wi})\right\}_{Field}$$

Given

$Q_{prod,\ Model} = 893.5\ cm^3\ (8.935E\text{-}04\ m^3)$

$S_{wi,\ Model} = 15.1\%$ $S_{wi,\ Field} = 13.0\%$

The field cumulative production will be:

$$Q_{prod,\ Field} = 65434.4\ m^3.$$

5.3.6.4 Field Prediction of Total Oil Recovery

The total oil recovery was scaled up using

$$(\%\ \text{HCPV Recovery})_{Field} = \left(\frac{Q_{prod}}{HCPV}\right) \times 100_{Field}.$$

$$= \left\{\frac{Q_{prod}}{(1 - S_{wi})\phi hw^2}\right\} \times 100_{Field}.$$

Substituting the calculated values on the previous page yields:

$$(\%\ \text{HCPV Recovery})_{Field} = 54.4\%.$$

Table 5.7 shows the scaled up total injection (production) times, cumulative total productions, and the total oil recoveries of Runs GTD6 and 2DT1 to 2DT6. It can be seen that using pure carbon dioxide yields the highest field recovery.

Table 5.7 - Prediction of Field Recovery.

Run No.	N_2 Content in Mixture (mole%)	Injection Rate (Gas/ Water) (M^3/day)	Gas Injection Time (months)	Water Injection Time (months)	Total Injection Time (years)	Cumulative Oil Production (sm^3)	Total Oil Recovery (%HCPV)
GTD6[8]	0.0	191.36	4.5	79.7	7.0	65434.4	54.4
2DT1	4.98	208.14	4.4	53.5	5.0	57712.5	48.0
2DT2	9.99	213.39	4.9	52.9	5.0	57153.8	47.5
2DT3	15.0	211.48	5.0	53.8	5.0	56872.1	47.3
2DT4	20.0	185.52	5.1	52.4	4.8	54022.5	44.9
2DT5	25.0	169.01	5.5	60.8	5.5	53889.5	44.8
2DT6	30.0	183.09	5.4	56.4	5.2	53026.8	44.1

The predicted values are based on experimental results. Due to differences in the geometry and production strategy between the physical model and the field reservoir, these scaled-up values could prove to be optimistic or pessimistic. Furthermore, in actual practice, the composition of the flue gas may be different from the compositions used in this study. The flue gas may contain, in fact, carbon dioxide, nitrogen, and 1 to 2% oxygen. The oxygen will oxidize the in-place oil. Depending on the oxygen content of the flue gas, operating conditions (pressure and temperature), and the injection rate, some heat will be generated. In any case, the oxygen will be converted into carbon dioxide, thus supplementing the carbon dioxide already injected, and the overall effect may not be significant.

An important aspect of the scaled model experiments is that the reservoir is assumed to be homogeneous. Unless the actual reservoir heterogeneities are known, inclusion of heterogeneities in scaled models is not justified.

CHAPTER 6

SUMMARY and CONCLUSIONS

In this investigation, selected experimental results obtained in the previous studies were reviewed, providing explanations for previously unexplained effects. A total of forty-six experiments were conducted for this phase of the experimental study to determine the sensitivity of oil recovery to the use of impure carbon dioxide containing nitrogen as the diluting gas, in the immiscible WAG displacement process. These forty-six experiments were carried out in two physical models: linear and two-dimensional. In addition, the effects of carbon dioxide partial pressure and volume were studied. Experimental results were scaled up using appropriate scaling groups to predict performance of a particular flood for the Aberfeldy field, Saskatchewan.

Based upon the experimental observations, the following conclusions are reached:

1. The solubility and diffusivity of carbon dioxide decrease with increasing nitrogen content, which has an adverse effect on process mechanisms.

2. A comparison of pure carbon dioxide and pure nitrogen runs with nitrogen-carbon dioxide mixture runs shows that if impure carbon dioxide contains a nitrogen volume up to 15.0 mole%, the oil recovery is only 6% lower than that for pure carbon dioxide. The recovery loss increases to 10% for a 30 mole% nitrogen concentration.

3. Increasing the carbon dioxide partial pressure in the nitrogen-carbon dioxide mixture results in an increase in recovery, while an increase in carbon dioxide partial volume shows the opposite trend.

4. With an increase in the volume of nitrogen in the carbon dioxide stream, the sweep efficiency of the immiscible WAG process is reduced, which results in a reduction in oil recovery. Also, the oil production rate decreases, while carbon dioxide production rate increases, as the volume of nitrogen in carbon dioxide increases.

5. The presence of a solution gas (methane) increases the effectiveness of the immiscible carbon dioxide WAG process by providing an internal driving force which helps to mobilize oil. Oil recovery increases by 10 to 15% due to the presence of a solution gas.

6. The operating pressure has a considerable effect on oil recovery. Oil recovery decreases with increasing pressure above the pressure at which the asphaltene precipitation ensues.

7. Velocity is an important factor determining the oil recovery efficiency of the process. Carbon dioxide should be injected at low velocities to retard its production, and to promote its diffusion into oil. Water should be injected at high velocities to minimize the effect of gravity segregation.

8. The use of a large total gas slug size, for example 40% HCPV in this study, is no more effective than a 20% HCPV slug, because of inefficient utilization of gas.

CHAPTER 7

RECOMMENDATIONS FOR FURTHER STUDIES

The following studies are recommended to extend the scope of this research.

1. Future experiments should be carried out at temperatures higher than 23°C, since the temperature affects the solubility and diffusivity of carbon dioxide into oil, which are important to the immiscible carbon dioxide process. At higher temperatures, the concentration of the carbonic acid formed by the reaction between the carbon dioxide gas and water will be higher, which may alter formation properties, as well as oil properties.

2. A three-dimensional model should be designed and fabricated to study the role of gravity in the presence of a bottom-water layer. In those cases where the formation is thick, but still suitable for the application of the immiscible carbon dioxide process, due to gravity, the injected gas will rise while water will flow down.

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APPENDIX A

Tabulated Data of All Experiments Conducted

TABLE A01

RESULTS OF RUN 1DT1

[0.20 HCPV CO2-N2 @ 1.0 MPa (0.092 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.7
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.39

Pore Volume [cm3] = 1110.0
Initial Oil Saturation [%] = 95.0
Hydrocarbon Pore Volume [cm3] = 1060.4
Carbon Dioxide Retention [%inj] = 39.71

Connate Water Saturation [%] = 5.0
Molar Density @ atm. [kmol/m3] = 0.04165
Absolute Permeability [darcies] = 11.3100
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	21.1	0.0	0.019	0.000	0.00	4.00	4.00	0.38	0.00	0.00	0.189
1.40	1.00	0.0	84.8	0.076	0.002	1.00	76.20	80.20	7.56	0.01	0.03	0.898
1.30	1.00	21.1	0.0	0.019	0.000	0.00	17.00	97.20	9.17	0.00	0.00	0.805
1.20	1.00	0.0	84.8	0.076	0.000	0.00	72.00	169.20	15.96	0.00	0.00	0.849
1.20	1.00	21.1	0.0	0.019	0.001	0.00	24.50	193.70	18.27	0.00	0.04	1.159
1.20	1.00	0.0	84.8	0.076	0.009	24.20	48.00	241.70	22.79	0.50	0.19	0.566
1.20	1.00	21.1	0.0	0.019	0.001	18.20	11.30	253.00	23.86	1.61	0.09	0.535
1.10	1.00	0.0	84.8	0.076	0.022	34.00	19.00	272.00	25.65	1.79	1.16	0.224
1.10	1.00	21.1	0.0	0.019	0.010	14.00	3.70	275.70	26.00	3.78	2.70	0.175
1.10	1.00	0.0	84.9	0.076	0.015	45.50	20.00	295.70	27.89	2.27	0.75	0.236
1.10	1.00	21.1	0.0	0.019	0.005	16.10	3.50	299.20	28.22	4.60	1.43	0.166
1.10	1.00	0.0	84.8	0.076	0.013	49.60	17.90	317.10	29.90	2.77	0.73	0.211
1.10	1.00	21.1	0.0	0.019	0.005	18.00	3.70	320.80	30.25	4.86	1.35	0.175
1.10	1.00	0.0	84.8	0.076	0.052	56.50	15.00	335.80	31.67	3.77	3.47	0.177
1.10	1.00	21.1	0.0	0.019	0.023	12.20	2.40	338.20	31.89	5.08	9.58	0.114
1.10	1.00	0.0	84.8	0.076	0.053	56.00	14.00	352.20	33.21	4.00	3.79	0.165
1.10	1.00	21.1	0.0	0.019	0.030	17.30	2.70	354.90	33.47	6.41	11.11	0.128

TABLE A01 (CONTINUED)

RESULTS OF RUN 1DT1
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.092 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.7
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.39

Pore Volume [cm3] = 1110.0
Initial Oil Saturation [%] = 95.0
Hydrocarbon Pore Volume [cm3] = 1060.4
Carbon Dioxide Retention [%inj] = 39.71

Connate Water Saturation [%] = 5.0
Molar Density @ atm. [kmol/m3] = 0.04165
Absolute Permeability [darcies] = 11.3100
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	84.8	0.076	0.113	59.00	11.50	366.40	34.55	5.13	9.83	0.136
1.10	1.00	21.1	0.0	0.019	0.031	15.50	2.20	368.60	34.76	7.05	14.09	0.104
1.10	1.00	0.0	84.8	0.076	0.114	56.50	14.70	383.30	36.15	3.84	7.76	0.173
1.10	1.00	0.0	259.3	0.234	0.380	206.00	42.00	425.30	40.11	4.90	9.05	0.162
1.10	1.00	0.0	251.7	0.227	0.265	217.80	32.20	457.50	43.14	6.76	8.23	0.128
1.10	1.00	0.0	258.0	0.232	0.145	238.50	17.50	475.00	44.79	13.63	8.29	0.068
1.10	1.00	0.0	250.3	0.225	0.058	231.50	19.00	494.00	46.59	12.18	3.05	0.076
1.10	1.00	0.0	250.4	0.226	0.031	239.00	12.00	506.00	47.72	19.92	2.58	0.048
0.01	0.01	0.0	0.0	0.000	0.147	78.50	22.50	528.50	49.84	3.49	6.53	

TABLE A02

RESULTS OF RUN 1DT02
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.091 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.8
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.56

Pore Volume [cm3] = 1113.5
Initial Oil Saturation [%] = 94.9
Hydrocarbon Pore Volume [cm3] = 1056.3
Carbon Dioxide Retention [%inj] = 34.42

Connate Water Saturation [%] = 5.1
Molar Density @ atm. [kmol/m3] = 0.04163
Absolute Permeability [darcies] = 10.7000
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	21.1	0.0	0.019	0.000	0.00	0.50	0.50	0.05	0.00	0.00	0.024
1.30	1.00	0.0	84.5	0.076	0.002	1.00	81.00	81.50	7.72	0.01	0.02	0.959
1.10	1.00	21.1	0.0	0.019	0.000	0.00	0.50	82.00	7.76	0.00	0.00	0.024
1.20	1.00	0.0	84.5	0.076	0.000	0.00	84.50	166.50	15.76	0.00	0.00	1.000
1.10	1.00	21.1	0.0	0.019	0.001	0.00	9.00	175.50	16.61	0.00	0.11	0.426
1.10	1.00	0.0	84.5	0.076	0.009	37.00	46.00	221.50	20.97	0.80	0.20	0.544
1.00	1.00	21.1	0.0	0.019	0.001	0.00	8.00	229.50	21.73	0.00	0.12	0.379
1.10	1.00	0.0	85.4	0.077	0.022	50.00	33.30	262.80	24.88	1.50	0.66	0.390
1.10	1.00	21.1	0.0	0.019	0.010	1.00	2.00	264.80	25.07	0.50	5.00	0.095
1.10	1.00	0.0	84.5	0.076	0.015	46.90	18.60	283.40	26.83	2.52	0.81	0.220
1.10	1.00	21.1	0.0	0.019	0.005	0.50	2.00	285.40	27.02	0.25	2.50	0.095
1.10	1.00	0.0	84.5	0.076	0.013	54.20	13.40	298.80	28.29	4.04	0.97	0.159
1.10	1.00	21.1	0.0	0.019	0.005	6.50	1.70	300.50	28.45	3.82	2.94	0.081
1.10	1.00	0.0	84.5	0.076	0.052	58.10	13.40	313.90	29.72	4.34	3.88	0.159
1.10	1.00	21.1	0.0	0.019	0.023	6.50	1.50	315.40	29.86	4.33	15.33	0.071
1.10	1.00	0.0	84.5	0.076	0.053	66.00	12.50	327.90	31.04	5.28	4.24	0.148
1.10	1.00	21.1	0.0	0.019	0.030	5.70	1.80	329.70	31.21	3.17	16.67	0.085

TABLE A02 (CONTINUED)

RESULTS OF RUN 1DT02
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.091 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.8
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.56

Pore Volume [cm3] = 1113.5
Initial Oil Saturation [%] = 94.9
Hydrocarbon Pore Volume [cm3] = 1056.3
Carbon Dioxide Retention [%inj] = 34.42

Connate Water Saturation [%] = 5.1
Molar Density @ atm. [kmol/m3] = 0.04163
Absolute Permeability [darcies] = 10.7000
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	84.5	0.076	0.113	65.50	11.00	340.70	32.25	5.95	10.27	0.130
1.10	1.00	21.1	0.0	0.019	0.031	4.00	1.50	342.20	32.40	2.67	20.67	0.071
1.10	1.00	0.0	84.6	0.076	0.114	66.00	15.00	357.20	33.82	4.40	7.60	0.177
1.10	1.00	0.0	253.7	0.228	0.380	217.00	33.00	390.20	36.94	6.58	11.52	0.130
1.10	1.00	0.0	249.1	0.224	0.265	214.00	35.00	425.20	40.25	6.11	7.57	0.141
1.10	1.00	0.0	249.9	0.224	0.145	213.00	37.00	462.20	43.76	5.76	3.92	0.148
1.10	1.00	0.0	248.7	0.223	0.058	230.00	19.00	481.20	45.56	12.11	3.05	0.076
1.10	1.00	0.0	249.5	0.224	0.031	235.80	14.20	495.40	46.90	16.61	2.18	0.057
1.10	1.00	0.0	249.9	0.224	0.025	239.00	11.00	506.40	47.94	21.73	2.27	0.044
0.01	0.01	0.0	0.0	0.000	0.177	78.50	22.50	528.90	50.07	3.49	7.87	

TABLE A03

RESULTS OF RUN 1DT3
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.091 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 36.1
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.78

Pore Volume [cm3] = 1121.2
Initial Oil Saturation [%] = 92.4
Hydrocarbon Pore Volume [cm3] = 1064.9
Carbon Dioxide Retention [%inj] = 21.91

Connate Water Saturation [%] = 7.6
Molar Density @ atm. [kmol/m3] = 0.04162
Absolute Permeability [darcies] = 10.5100
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	21.3	0.0	0.019	0.000	0.00	0.50	0.50	0.05	0.00	0.00	0.023
1.40	1.00	0.0	85.2	0.076	0.002	0.50	82.40	82.90	7.78	0.01	0.02	0.967
1.10	1.00	21.3	0.0	0.019	0.004	0.00	1.00	83.90	7.88	0.00	4.00	0.047
1.10	1.00	0.0	85.2	0.076	0.003	3.50	79.00	162.90	15.30	0.04	0.04	0.927
1.10	1.00	21.3	0.0	0.019	0.004	8.10	9.00	171.90	16.14	0.90	0.44	0.423
1.10	1.00	0.0	85.2	0.076	0.003	26.50	46.00	217.90	20.46	0.58	0.07	0.540
1.00	1.00	21.3	0.0	0.019	0.010	12.00	8.00	225.90	21.21	1.50	1.25	0.376
1.10	1.00	0.0	85.2	0.076	0.027	34.50	38.50	264.40	24.83	0.90	0.70	0.452
1.10	1.00	21.3	0.0	0.019	0.013	19.00	2.00	266.40	25.02	9.50	6.50	0.094
1.10	1.00	0.0	85.1	0.076	0.017	49.00	18.00	284.40	26.71	2.72	0.94	0.211
1.10	1.00	21.3	0.0	0.019	0.007	20.00	2.00	286.40	26.89	10.00	3.50	0.094
1.10	1.00	0.0	85.2	0.076	0.062	52.50	13.00	299.40	28.12	4.04	4.77	0.153
1.10	1.00	21.3	0.0	0.019	0.018	30.50	3.50	302.90	28.44	8.71	5.14	0.164
1.10	1.00	0.0	85.2	0.076	0.058	52.70	13.90	316.80	29.75	3.79	4.17	0.163
1.10	1.00	21.3	0.0	0.019	0.037	17.50	1.50	318.30	29.89	11.67	24.67	0.070
1.10	1.00	0.0	85.2	0.076	0.060	54.00	12.50	330.80	31.06	4.32	4.80	0.147
1.10	1.00	21.3	0.0	0.019	0.053	5.50	2.00	332.80	31.25	2.75	26.50	0.094

TABLE A03 (CONTINUED)

RESULTS OF RUN 1DT3
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.091 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 36.1
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.78

Pore Volume [cm3] = 1121.2
Initial Oil Saturation [%] = 92.4
Hydrocarbon Pore Volume [cm3] = 1064.9
Carbon Dioxide Retention [%inj] = 21.91

Connate Water Saturation [%] = 7.6
Molar Density @ atm. [kmol/m3] = 0.04162
Absolute Permeability [darcies] = 10.5100
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	87.4	0.078	0.107	68.50	11.70	344.50	32.35	5.85	9.15	0.134
1.10	1.00	21.3	0.0	0.019	0.036	21.00	1.50	346.00	32.49	14.00	24.00	0.070
1.10	1.00	0.0	85.2	0.076	0.088	56.50	15.00	361.00	33.90	3.77	5.87	0.176
1.10	1.00	0.0	252.3	0.225	0.400	203.00	40.00	401.00	37.66	5.07	10.00	0.159
1.10	1.00	0.0	251.5	0.224	0.289	220.50	28.30	429.30	40.31	7.79	10.21	0.113
1.10	1.00	0.0	250.4	0.223	0.166	227.00	20.00	449.30	42.19	11.35	8.30	0.080
1.10	1.00	0.0	257.4	0.230	0.058	244.00	13.00	462.30	43.41	18.77	4.46	0.051
1.10	1.00	0.0	254.1	0.227	0.048	239.00	11.00	473.30	44.45	21.73	4.36	0.043
1.10	1.00	0.0	254.3	0.227	0.047	240.00	10.00	483.30	45.38	24.00	4.70	0.039
0.01	0.01	0.0	0.0	0.000	0.281	212.50	25.50	508.80	47.78	8.33	11.02	

TABLE A04

RESULTS OF RUN 1DT4

[0.20 HCPV CO2-N2 @ 1.0 MPa (0.090 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.6
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.05

Pore Volume [cm3] = 1106.5
Initial Oil Saturation [%] = 95.5
Hydrocarbon Pore Volume [cm3] = 1057.0
Carbon Dioxide Retention [%inj] = 14.72

Connate Water Saturation [%] = 4.5
Molar Density @ atm. [kmol/m3] = 0.04160
Absolute Permeability [darcies] = 10.7700
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	21.2	0.0	0.019	0.000	0.00	1.00	1.00	0.09	0.00	0.00	0.047
1.30	1.00	0.0	84.5	0.076	0.002	0.50	79.50	80.50	7.62	0.01	0.03	0.940
1.10	1.00	21.2	0.0	0.019	0.000	0.00	1.20	81.70	7.73	0.00	0.00	0.057
1.10	1.00	0.0	84.6	0.076	0.000	0.00	82.00	163.70	15.49	0.00	0.00	0.970
1.10	1.00	21.2	0.0	0.019	0.004	0.00	8.00	171.70	16.24	0.00	0.50	0.378
1.10	1.00	0.0	84.6	0.076	0.052	22.80	55.20	226.90	21.47	0.41	0.94	0.653
1.00	1.00	21.2	0.0	0.019	0.010	4.20	5.10	232.00	21.95	0.82	1.96	0.241
1.10	1.00	0.0	84.5	0.076	0.055	46.60	33.20	265.20	25.09	1.40	1.66	0.393
1.10	1.00	21.2	0.0	0.019	0.003	2.00	2.00	267.20	25.28	1.00	1.50	0.095
1.10	1.00	0.0	84.6	0.076	0.058	60.50	20.50	287.70	27.22	2.95	2.83	0.242
1.10	1.00	21.2	0.0	0.019	0.002	5.50	2.00	289.70	27.41	2.75	1.00	0.095
1.10	1.00	0.0	84.6	0.076	0.031	63.00	16.00	305.70	28.92	3.94	1.94	0.189
1.10	1.00	21.2	0.0	0.019	0.013	4.00	1.50	307.20	29.06	2.67	8.67	0.071
1.10	1.00	0.0	84.5	0.076	0.121	69.50	11.00	318.20	30.10	6.32	11.00	0.130
1.10	1.00	21.2	0.0	0.019	0.031	2.00	1.00	319.20	30.20	2.00	31.00	0.047
1.10	1.00	0.0	84.7	0.077	0.141	67.00	12.00	331.20	31.33	5.58	11.75	0.142
1.10	1.00	21.2	0.0	0.019	0.039	11.50	1.50	332.70	31.48	7.67	26.00	0.071

TABLE A04 (CONTINUED)

RESULTS OF RUN 1DT4

[0.20 HCPV CO2-N2 @ 1.0 MPa (0.090 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.6
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.05

Pore Volume [cm3] = 1106.5
Initial Oil Saturation [%] = 95.5
Hydrocarbon Pore Volume [cm3] = 1057.0
Carbon Dioxide Retention [%inj] = 14.72

Connate Water Saturation [%] = 4.5
Molar Density @ atm. [kmol/m3] = 0.04160
Absolute Permeability [darcies] = 10.7700
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	84.6	0.076	0.121	57.60	11.20	343.90	32.54	5.14	10.80	0.132
1.10	1.00	21.2	0.0	0.019	0.068	15.00	2.00	345.90	32.72	7.50	34.00	0.095
1.10	1.00	0.0	84.6	0.076	0.129	66.50	9.30	355.20	33.60	7.15	13.87	0.110
1.10	1.00	0.0	256.8	0.232	0.310	215.00	35.00	390.20	36.92	6.14	8.86	0.136
1.10	1.00	0.0	249.3	0.225	0.227	226.00	22.00	412.20	39.00	10.27	10.32	0.088
1.10	1.00	0.0	249.1	0.225	0.126	227.00	21.50	433.70	41.03	10.56	5.86	0.086
1.10	1.00	0.0	249.9	0.226	0.120	241.00	9.50	443.20	41.93	25.37	12.63	0.038
1.10	1.00	0.0	254.6	0.230	0.114	240.00	10.00	453.20	42.88	24.00	11.40	0.039
0.01	0.01	0.0	0.0	0.000	0.284	96.00	25.00	478.20	45.24	3.84	11.36	

TABLE A05

RESULTS OF RUN 1DT5

[0.20 HCPV CO2-N2 @ 1.0 MPa (0.090 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.2
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.13

Pore Volume [cm3] = 1093.0
Initial Oil Saturation [%] = 95.3
Hydrocarbon Pore Volume [cm3] = 1055.7
Carbon Dioxide Retention [%inj] = 10.13

Connate Water Saturation [%] = 4.5
Molar Density @ atm. [kmol/m3] = 0.04159
Absolute Permeability [darcies] = 10.6300
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	21.1	0.0	0.019	0.000	0.00	1.00	1.00	0.09	0.00	0.00	0.047
1.30	1.00	0.0	84.5	0.077	0.000	0.50	79.00	80.00	7.58	0.01	0.00	0.935
1.20	1.00	21.1	0.0	0.019	0.000	0.00	1.00	81.00	7.67	0.00	0.00	0.047
1.20	1.00	0.0	84.5	0.077	0.001	3.00	80.00	161.00	15.25	0.04	0.01	0.947
1.20	1.00	21.1	0.0	0.019	0.000	8.50	9.50	170.50	16.15	0.89	0.00	0.450
1.10	1.00	0.0	84.4	0.077	0.070	38.00	48.50	219.00	20.74	0.78	1.44	0.574
1.20	1.00	21.1	0.0	0.019	0.044	18.50	11.50	230.50	21.83	1.61	3.83	0.544
1.10	1.00	0.0	84.5	0.077	0.056	40.00	27.20	257.70	24.41	1.47	2.06	0.322
1.10	1.00	21.1	0.0	0.019	0.011	13.80	2.00	259.70	24.60	6.90	5.50	0.095
1.10	1.00	0.0	84.5	0.077	0.154	50.50	21.00	280.70	26.59	2.40	7.33	0.249
1.10	1.00	21.1	0.0	0.019	0.016	20.20	2.00	282.70	26.78	10.10	8.00	0.095
1.10	1.00	0.0	84.5	0.077	0.117	45.50	14.50	297.20	28.15	3.14	8.07	0.172
1.10	1.00	21.1	0.0	0.019	0.010	15.00	1.50	298.70	28.29	10.00	6.67	0.071
1.10	1.00	0.0	84.2	0.077	0.099	53.00	16.00	314.70	29.81	3.31	6.19	0.190
1.10	1.00	21.1	0.0	0.019	0.032	17.50	1.00	315.70	29.90	17.50	32.00	0.047
1.10	1.00	0.0	84.5	0.077	0.129	50.50	12.00	327.70	31.04	4.21	10.75	0.142
1.10	1.00	21.1	0.0	0.019	0.036	17.00	1.50	329.20	31.18	11.33	24.00	0.071

TABLE A05 (CONTINUED)

RESULTS OF RUN 1DT5
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.090 g-mol) 4:1 WAG, 10 Slugs, DEAD OIL]

Porosity [%] = 35.2
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.13

Pore Volume [cm3] = 1093.0
Initial Oil Saturation [%] = 95.3
Hydrocarbon Pore Volume [cm3] = 1055.7
Carbon Dioxide Retention [%inj] = 10.13

Connate Water Saturation [%] = 4.5
Molar Density @ atm. [kmol/m3] = 0.04159
Absolute Permeability [darcies] = 10.6300
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	84.5	0.077	0.239	43.00	10.00	339.20	32.13	4.30	23.90	0.118
1.10	1.00	21.1	0.0	0.019	0.026	2.00	1.50	340.70	32.27	1.33	17.33	0.071
1.10	1.00	0.0	84.8	0.078	0.260	68.60	10.90	351.60	33.30	6.29	23.85	0.129
1.10	1.00	0.0	253.2	0.232	0.209	215.00	35.50	387.10	36.67	6.06	5.89	0.140
1.10	1.00	0.0	257.1	0.235	0.119	221.00	33.00	420.10	39.79	6.70	3.61	0.128
1.10	1.00	0.0	250.4	0.229	0.134	230.00	19.00	439.10	41.59	12.11	7.05	0.076
1.10	1.00	0.0	251.6	0.230	0.097	236.00	14.00	453.10	42.92	16.86	6.93	0.056
1.10	1.00	0.0	251.2	0.230	0.107	241.00	10.00	463.10	43.87	24.10	10.70	0.040
0.01	0.01	0.0	0.0	0.000	0.289	114.00	26.00	475.10	45.00	4.38	11.12	

TABLE A06

RESULTS OF RUN 1DT6
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.090 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.7
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.38

Pore Volume [cm3] = 1110.0
Initial Oil Saturation [%] = 95.5
Hydrocarbon Pore Volume [cm3] = 1060.5
Carbon Dioxide Retention [%inj] = 9.73

Connate Water Saturation [%] = 4.5
Molar Density @ atm. [kmol/m3] = 0.04158
Absolute Permeability [darcies] = 10.7300
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	21.2	0.0	0.019	0.000	0.00	0.50	0.50	0.05	0.00	0.00	0.024
1.30	1.00	0.0	84.8	0.076	0.003	0.50	81.00	81.50	7.69	0.01	0.04	0.955
1.20	1.00	21.2	0.0	0.019	0.000	0.00	10.80	92.30	8.70	0.00	0.00	0.509
1.20	1.00	0.0	84.9	0.076	0.005	0.30	82.50	174.80	16.48	0.00	0.06	0.972
1.20	1.00	21.2	0.0	0.019	0.014	1.50	14.20	189.00	17.82	0.11	0.99	0.670
1.10	1.00	0.0	84.9	0.076	0.002	36.00	39.00	228.00	21.50	0.92	0.05	0.460
1.20	1.00	21.2	0.0	0.019	0.022	6.00	3.50	231.50	21.83	1.71	6.29	0.165
1.10	1.00	0.0	84.8	0.076	0.054	59.00	18.50	250.00	23.57	3.19	2.92	0.218
1.10	1.00	21.2	0.0	0.019	0.017	14.50	4.00	254.00	23.95	3.63	4.25	0.189
1.10	1.00	0.0	84.9	0.076	0.113	50.50	14.50	268.50	25.32	3.48	7.79	0.171
1.10	1.00	21.2	0.0	0.019	0.016	11.60	2.40	270.90	25.54	4.83	6.67	0.113
1.10	1.00	0.0	84.9	0.076	0.117	59.00	13.00	283.90	26.77	4.54	9.00	0.153
1.10	1.00	21.2	0.0	0.019	0.082	9.50	2.50	286.40	27.01	3.80	32.80	0.118
1.10	1.00	0.0	84.8	0.076	0.032	68.50	9.50	295.90	27.90	7.21	3.37	0.112
1.10	1.00	21.2	0.0	0.019	0.064	12.00	2.50	298.40	28.14	4.80	25.60	0.118
1.10	1.00	0.0	84.9	0.076	0.078	61.00	9.00	307.40	28.99	6.78	8.67	0.106
1.10	1.00	21.2	0.0	0.019	0.043	10.30	1.70	309.10	29.15	6.06	25.29	0.080

TABLE A06 (CONTINUED)

RESULTS OF RUN 1DT6
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.090 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.7
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.38

Pore Volume [cm3] = 1110.0
Initial Oil Saturation [%] = 95.5
Hydrocarbon Pore Volume [cm3] = 1060.5
Carbon Dioxide Retention [%inj] = 9.73

Connate Water Saturation [%] = 4.5
Molar Density @ atm. [kmol/m3] = 0.04158
Absolute Permeability [darcies] = 10.7300
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	84.9	0.076	0.119	66.50	13.00	322.10	30.37	5.12	9.15	0.153
1.10	1.00	21.2	0.0	0.019	0.035	10.50	1.00	323.10	30.47	10.50	35.00	0.047
1.10	1.00	0.0	84.9	0.076	0.123	66.50	11.10	334.20	31.51	5.99	11.08	0.131
1.10	1.00	0.0	255.4	0.230	0.370	213.00	35.50	369.70	34.86	6.00	10.42	0.139
1.10	1.00	0.0	250.0	0.225	0.363	219.00	31.00	400.70	37.78	7.06	11.71	0.124
1.10	1.00	0.0	248.4	0.224	0.151	227.00	21.00	421.70	39.76	10.81	7.19	0.085
1.10	1.00	0.0	252.0	0.227	0.135	235.00	15.00	436.70	41.18	15.67	9.00	0.060
1.10	1.00	0.0	249.0	0.224	0.125	238.00	11.50	448.20	42.26	20.70	10.87	0.046
0.01	0.01	0.0	0.0	0.000	0.190	121.00	20.00	468.20	44.15	6.05	9.50	

TABLE A07

RESULTS OF RUN 1DT07
[0.20 HCPV CO2 @ 1.0 MPa (0.092 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.8
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.02

Pore Volume [cm3] = 1114.0
Initial Oil Saturation [%] = 95.0
Hydrocarbon Pore Volume [cm3] = 1058.1
Carbon Dioxide Retention [%inj] = 43.65

Connate Water Saturation [%] = 5.0
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 11.0400
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	21.1	0.0	0.019	0.000	0.00	2.00	2.00	0.19	0.00	0.00	0.095
1.20	1.00	0.0	84.6	0.076	0.000	1.00	77.60	79.60	7.52	0.01	0.00	0.917
1.10	1.00	21.1	0.0	0.019	0.001	0.00	15.20	94.80	8.96	0.00	0.07	0.719
1.20	1.00	0.0	84.7	0.076	0.000	0.00	74.50	169.30	16.00	0.00	0.00	0.880
1.10	1.00	21.1	0.0	0.019	0.000	1.00	24.50	193.80	18.32	0.04	0.00	1.158
1.20	1.00	0.0	84.6	0.076	0.001	20.50	35.50	229.30	21.67	0.58	0.03	0.419
1.20	1.00	21.1	0.0	0.019	0.001	13.20	10.70	240.00	22.68	1.23	0.09	0.506
1.10	1.00	0.0	84.6	0.076	0.021	30.20	33.60	273.60	25.86	0.90	0.62	0.397
1.10	1.00	21.1	0.0	0.019	0.007	19.50	7.40	281.00	26.56	2.64	0.95	0.350
1.10	1.00	0.0	84.6	0.076	0.010	45.50	13.20	294.20	27.80	3.45	0.76	0.156
1.10	1.00	21.1	0.0	0.019	0.009	21.50	3.00	297.20	28.09	7.17	3.00	0.142
1.10	1.00	0.0	84.6	0.076	0.014	50.00	14.20	311.40	29.43	3.52	0.99	0.168
1.10	1.00	21.1	0.0	0.019	0.001	22.00	2.50	313.90	29.67	8.80	0.40	0.118
1.00	1.00	0.0	84.7	0.076	0.049	51.30	11.20	325.10	30.72	4.58	4.37	0.132
1.10	1.00	21.1	0.0	0.019	0.020	19.20	2.80	327.90	30.99	6.86	7.14	0.132
1.10	1.00	0.0	84.6	0.076	0.051	46.50	20.00	347.90	32.88	2.32	2.55	0.236
1.10	1.00	21.1	0.0	0.019	0.031	20.50	3.40	351.30	33.20	6.03	9.12	0.161

TABLE A07 (CONTINUED)

RESULTS OF RUN 1DT07
[0.20 HCPV CO2 @ 1.0 MPa (0.092 g-mol) 4:1 WAG, 10 Slugs, DEAD OIL]

Porosity [%] = 35.8
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.02

Pore Volume [cm3] = 1114.0
Initial Oil Saturation [%] = 95.0
Hydrocarbon Pore Volume [cm3] = 1058.1
Carbon Dioxide Retention [%inj] = 43.65

Connate Water Saturation [%] = 5.0
Molar Density @ atm. [kmol/m3] = 0.04166
Absolute Permeability [darcies] = 11.0400
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	84.6	0.076	0.104	40.00	20.00	371.30	35.09	2.00	5.20	0.236
1.10	1.00	21.1	0.0	0.019	0.018	19.00	6.80	378.10	35.73	2.79	2.65	0.322
1.10	1.00	0.0	84.6	0.076	0.107	41.50	20.50	398.60	37.67	2.02	5.22	0.242
1.10	1.00	0.0	247.3	0.222	0.308	173.00	70.00	468.60	44.29	2.47	4.40	0.283
1.10	1.00	0.0	246.6	0.221	0.143	206.00	40.00	508.60	48.07	5.15	3.57	0.162
1.10	1.00	0.0	245.4	0.220	0.153	215.00	31.00	539.60	51.00	6.94	4.94	0.126
1.10	1.00	0.0	247.8	0.222	0.194	232.50	16.50	556.10	52.56	14.09	11.76	0.067
1.10	1.00	0.0	246.9	0.222	0.083	235.00	12.00	568.10	53.69	19.58	6.92	0.049
0.01	0.01	0.0	0.0	0.000	0.060	58.00	44.00	612.10	57.85	1.32	1.36	

TABLE A08

RESULTS OF RUN 1DT08
[0.20 HCPV CO2-N2 @ 1.00 MPa (0.092 g-mol) 4:1 WAG, 10 Slugs, DEAD OIL]

Porosity [%] = 36.4
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.18

Pore Volume [cm3] = 1133.0
Initial Oil Saturation [%] = 95.0
Hydrocarbon Pore Volume [cm3] = 1075.8
Carbon Dioxide Retention [%inj] = 43.41

Connate Water Saturation [%] = 5.0
Molar Density @ atm. [kmol/m3] = 0.04165
Absolute Permeability [darcies] = 11.1800
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	21.4	0.0	0.019	0.000	0.00	3.50	3.50	0.33	0.00	0.00	0.163
1.20	1.00	0.0	86.1	0.076	0.001	0.00	83.80	87.30	8.11	0.00	0.01	0.973
1.20	1.00	21.4	0.0	0.019	0.001	0.00	17.00	104.30	9.70	0.00	0.06	0.793
1.10	1.00	0.0	86.5	0.076	0.000	0.00	74.50	178.80	16.62	0.00	0.00	0.861
1.10	1.00	21.4	0.0	0.019	0.000	3.00	33.50	212.30	19.73	0.09	0.00	1.562
1.10	1.00	0.0	86.1	0.076	0.010	14.20	38.30	250.60	23.29	0.37	0.26	0.445
1.10	1.00	21.4	0.0	0.019	0.004	17.50	17.00	267.60	24.87	1.03	0.24	0.793
1.10	1.00	0.0	86.1	0.076	0.022	32.70	21.80	289.40	26.90	1.50	1.01	0.253
1.10	1.00	21.4	0.0	0.019	0.004	22.50	6.50	295.90	27.51	3.46	0.62	0.303
1.10	1.00	0.0	86.1	0.076	0.016	42.40	16.10	312.00	29.00	2.63	0.99	0.187
1.10	1.00	21.4	0.0	0.019	0.011	26.00	4.00	316.00	29.37	6.50	2.75	0.186
1.10	1.00	0.0	86.1	0.076	0.014	46.50	14.00	330.00	30.67	3.32	1.00	0.163
1.10	1.00	21.4	0.0	0.019	0.016	30.00	3.00	333.00	30.95	10.00	5.33	0.140
1.10	1.00	0.0	86.1	0.076	0.052	45.00	11.00	344.00	31.98	4.09	4.73	0.128
1.10	1.00	21.4	0.0	0.019	0.030	30.50	3.00	347.00	32.26	10.17	10.00	0.140
1.10	1.00	0.0	86.1	0.076	0.053	46.60	9.40	356.40	33.13	4.96	5.64	0.109
1.10	1.00	21.4	0.0	0.019	0.038	28.70	3.80	360.20	33.48	7.55	10.00	0.177

TABLE A08 (CONTINUED)

RESULTS OF RUN 1DT08
[0.20 HCPV CO2-N2 @ 1.00 MPa (0.092 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 36.4
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.18

Pore Volume [cm3] = 1133.0
Initial Oil Saturation [%] = 95.0
Hydrocarbon Pore Volume [cm3] = 1075.8
Carbon Dioxide Retention [%inj] = 43.41

Connate Water Saturation [%] = 5.0
Molar Density @ atm. [kmol/m3] = 0.04165
Absolute Permeability [darcies] = 11.1800
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	86.1	0.076	0.122	44.00	14.00	374.20	34.78	3.14	8.71	0.163
1.10	1.00	21.4	0.0	0.019	0.034	27.30	3.70	377.90	35.13	7.38	9.19	0.172
1.10	1.00	0.0	100.4	0.089	0.114	55.00	18.00	395.90	36.80	3.06	6.33	0.179
1.10	1.00	0.0	240.7	0.212	0.153	164.00	73.00	468.90	43.59	2.25	2.10	0.303
1.10	1.00	0.0	242.4	0.214	0.151	203.00	37.00	505.90	47.03	5.49	4.08	0.153
1.10	1.00	0.0	246.2	0.217	0.114	222.00	24.00	529.90	49.26	9.25	4.75	0.097
1.10	1.00	0.0	243.5	0.215	0.110	216.00	26.00	555.90	51.67	8.31	4.23	0.107
1.10	1.00	0.0	243.9	0.215	0.107	230.50	11.50	567.40	52.74	20.04	9.30	0.047
0.01	0.01	0.0	0.0	0.000	0.160	82.00	30.00	597.40	55.53	2.73	5.33	

TABLE A09

RESULTS OF RUN 1DT09
[0.20 HCPV CO2-N2 @ 1.00 MPa (0.091 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 36.1
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.32

Pore Volume [cm3] = 1121.0
Initial Oil Saturation [%] = 94.7
Hydrocarbon Pore Volume [cm3] = 1061.7
Carbon Dioxide Retention [%inj] = 40.60

Connate Water Saturation [%] = 5.3
Molar Density @ atm. [kmol/m3] = 0.04163
Absolute Permeability [darcies] = 11.1400
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.20	1.00	21.2	0.0	0.019	0.000	0.00	9.00	9.00	0.85	0.00	0.00	0.424
1.20	1.00	0.0	84.9	0.076	0.001	0.00	83.50	92.50	8.71	0.00	0.01	0.983
1.20	1.00	21.2	0.0	0.019	0.001	0.00	27.00	119.50	11.26	0.00	0.04	1.272
1.20	1.00	0.0	84.9	0.076	0.003	0.00	65.70	185.20	17.44	0.00	0.05	0.773
1.10	1.00	21.2	0.0	0.019	0.000	4.80	33.20	218.40	20.57	0.14	0.00	1.564
1.10	1.00	0.0	84.9	0.076	0.011	16.90	30.10	248.50	23.41	0.56	0.37	0.354
1.10	1.00	21.2	0.0	0.019	0.004	17.60	14.30	262.80	24.75	1.23	0.28	0.674
1.10	1.00	0.0	84.9	0.076	0.023	32.00	25.00	287.80	27.11	1.28	0.92	0.294
1.10	1.00	21.2	0.0	0.019	0.005	8.00	4.00	291.80	27.48	2.00	1.25	0.188
1.10	1.00	0.0	85.0	0.076	0.017	51.40	23.10	314.90	29.66	2.23	0.74	0.272
1.10	1.00	21.2	0.0	0.019	0.000	26.20	4.80	319.70	30.11	5.46	0.00	0.226
1.10	1.00	0.0	84.9	0.076	0.016	48.20	11.80	331.50	31.22	4.08	1.36	0.139
1.10	1.00	21.2	0.0	0.019	0.014	22.00	2.70	334.20	31.48	8.15	5.19	0.127
1.10	1.00	0.0	84.9	0.076	0.058	52.80	9.50	343.70	32.37	5.56	6.11	0.112
1.10	1.00	21.2	0.0	0.019	0.011	26.40	2.20	345.90	32.58	12.00	5.00	0.104
1.10	1.00	0.0	85.1	0.076	0.063	52.50	8.00	353.90	33.33	6.56	7.88	0.094
1.10	1.00	21.2	0.0	0.019	0.018	2.90	11.00	364.90	34.37	0.26	1.64	0.518

TABLE A09 (CONTINUED)

RESULTS OF RUN 1DT09

[0.20 HCPV CO2-N2 @ 1.00 MPa (0.091 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 36.1
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.32

Pore Volume [cm3] = 1121.0
Initial Oil Saturation [%] = 94.7
Hydrocarbon Pore Volume [cm3] = 1061.7
Carbon Dioxide Retention [%inj] = 40.60

Connate Water Saturation [%] = 5.3
Molar Density @ atm. [kmol/m3] = 0.04163
Absolute Permeability [darcies] = 11.1400
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	84.9	0.076	0.139	43.50	10.50	375.40	35.36	4.14	13.24	0.124
1.10	1.00	21.2	0.0	0.019	0.021	27.80	3.20	378.60	35.66	8.69	6.56	0.151
1.10	1.00	0.0	84.9	0.076	0.130	43.00	14.00	392.60	36.98	3.07	9.29	0.165
1.10	1.00	0.0	251.4	0.224	0.126	198.00	45.00	437.60	41.22	4.40	2.80	0.179
1.10	1.00	0.0	246.4	0.220	0.153	205.50	38.50	476.10	44.84	5.34	3.97	0.156
1.10	1.00	0.0	245.7	0.219	0.112	212.00	31.00	507.10	47.76	6.84	3.61	0.126
1.10	1.00	0.0	243.2	0.217	0.109	229.00	12.00	519.10	48.89	19.08	9.08	0.049
0.01	0.01	0.0	0.0	0.000	0.372	133.00	58.00	577.10	54.36	2.29	6.41	

TABLE A10

RESULTS OF RUN 1DT10
[0.20 HCPV CO2/N2 @ 1.0 MPa (0.090 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.7
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.30

Pore Volume [cm3] = 1111.0
Initial Oil Saturation [%] = 95.1
Hydrocarbon Pore Volume [cm3] = 1056.0
Carbon Dioxide Retention [%inj] = 20.63

Connate Water Saturation [%] = 4.9
Molar Density @ atm. [kmol/m3] = 0.04133
Absolute Permeability [darcies] = 11.5300
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GJR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	21.1	0.0	0.019	0.001	0.00	1.00	1.00	0.09	0.00	1.00	0.047
1.10	1.00	0.0	84.5	0.076	0.000	0.00	84.00	85.00	8.05	0.00	0.00	0.994
1.20	1.00	21.1	0.0	0.019	0.000	0.00	21.80	106.80	10.11	0.00	0.00	1.033
1.10	1.00	0.0	84.5	0.076	0.000	0.00	66.80	173.60	16.44	0.00	0.00	0.791
1.10	1.00	21.1	0.0	0.019	0.000	6.00	26.90	200.50	18.99	0.22	0.00	1.274
1.10	1.00	0.0	84.5	0.076	0.069	19.00	39.70	240.20	22.75	0.48	1.74	0.470
1.10	1.00	21.1	0.0	0.019	0.002	11.50	7.00	247.20	23.41	1.64	0.29	0.332
1.10	1.00	0.0	84.5	0.076	0.069	33.30	35.70	282.90	26.79	0.93	1.93	0.423
1.10	1.00	21.1	0.0	0.019	0.003	19.20	5.80	288.70	27.34	3.31	0.52	0.275
1.10	1.00	0.0	84.5	0.076	0.073	46.50	18.50	307.20	29.09	2.51	3.95	0.219
1.10	1.00	21.1	0.0	0.019	0.012	15.50	6.50	313.70	29.71	2.38	1.85	0.308
1.10	1.00	0.0	84.5	0.076	0.114	39.00	25.50	339.20	32.12	1.53	4.47	0.302
1.10	1.00	21.1	0.0	0.019	0.008	14.00	4.00	343.20	32.50	3.50	2.00	0.189
1.10	1.00	0.0	84.5	0.076	0.099	48.00	18.00	361.20	34.20	2.67	5.50	0.213
1.10	1.00	21.1	0.0	0.019	0.024	25.00	4.00	365.20	34.58	6.25	6.00	0.189
1.10	1.00	0.0	84.5	0.076	0.136	45.50	16.50	381.70	36.15	2.76	8.24	0.195
1.10	1.00	21.1	0.0	0.019	0.033	25.00	3.50	385.20	36.48	7.14	9.43	0.166

TABLE A10 (CONTINUED)

RESULTS OF RUN 1DT10
[0.20 HCPV CO2/N2 @ 1.0 MPa (0.090 g-mol) 4:1 WAG, 10 Slugs, DEAD OIL]

Porosity [%] = 35.7
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.30

Pore Volume [cm3] = 1111.0
Initial Oil Saturation [%] = 95.1
Hydrocarbon Pore Volume [cm3] = 1056.0
Carbon Dioxide Retention [%inj] = 20.63

Connate Water Saturation [%] = 4.9
Molar Density @ atm. [kmol/m3] = 0.04133
Absolute Permeability [darcies] = 11.5300
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	84.5	0.076	0.217	39.00	20.00	405.20	38.37	1.95	10.85	0.237
1.10	1.00	21.1	0.0	0.019	0.049	14.50	2.00	407.20	38.56	7.25	24.50	0.095
1.10	1.00	0.0	84.5	0.076	0.191	51.00	17.00	424.20	40.17	3.00	11.24	0.201
1.10	1.00	0.0	244.7	0.220	0.162	200.00	41.00	465.20	44.05	4.88	3.95	0.168
1.10	1.00	0.0	249.9	0.225	0.156	219.00	29.00	494.20	46.80	7.55	5.38	0.116
1.10	1.00	0.0	247.6	0.223	0.115	225.00	21.50	515.70	48.84	10.47	5.35	0.087
1.10	1.00	0.0	246.4	0.222	0.112	231.00	15.00	530.70	50.26	15.40	7.47	0.061
0.01	0.01	0.0	0.0	0.000	0.319	119.00	45.00	575.70	54.52	2.64	7.09	

TABLE A11

RESULTS OF RUN 1DT11
[0.20 HCPV CO2-N2 @ 1.00 MPa (0.089 g-mol) 4:1 WAG,10 Slugs, DEAD OIL] LC

Porosity [%] = 35.8
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.31

Pore Volume [cm3] = 1112.0
Initial Oil Saturation [%] = 94.1
Hydrocarbon Pore Volume [cm3] = 1065.0
Carbon Dioxide Retention [%inj] = 8.87

Connate Water Saturation [%] = 5.9
Molar Density @ atm. [kmol/m3] = 0.04160
Absolute Permeability [darcies] = 11.8900
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	20.9	0.0	0.019	0.000	0.00	5.50	5.50	0.52	0.00	0.00	0.263
1.10	1.00	0.0	83.7	0.075	0.002	0.00	82.50	88.00	8.26	0.00	0.02	0.985
1.20	1.00	20.9	0.0	0.019	0.000	0.00	22.00	110.00	10.33	0.00	0.00	1.053
1.10	1.00	0.0	83.7	0.075	0.000	0.00	65.50	175.50	16.48	0.00	0.00	0.782
1.10	1.00	20.9	0.0	0.019	0.002	7.00	27.50	203.00	19.06	0.25	0.07	1.316
1.10	1.00	0.0	83.7	0.075	0.071	16.60	37.40	240.40	22.57	0.44	1.90	0.447
1.10	1.00	20.9	0.0	0.019	0.010	8.00	7.00	247.40	23.23	1.14	1.43	0.335
1.10	1.00	0.0	83.7	0.075	0.010	36.00	37.00	284.40	26.70	0.97	0.27	0.442
1.10	1.00	20.9	0.0	0.019	0.003	9.50	3.50	287.90	27.03	2.71	0.86	0.168
1.10	1.00	0.0	83.7	0.075	0.072	49.00	23.50	311.40	29.24	2.09	3.06	0.281
1.10	1.00	20.9	0.0	0.019	0.009	6.90	2.10	313.50	29.44	3.29	4.29	0.101
1.10	1.00	0.0	83.8	0.075	0.061	56.50	18.00	331.50	31.13	3.14	3.39	0.215
1.10	1.00	20.9	0.0	0.019	0.013	22.80	5.20	336.70	31.61	4.38	2.50	0.249
1.10	1.00	0.0	83.7	0.075	0.180	41.50	18.50	355.20	33.35	2.24	9.73	0.221
1.10	1.00	20.9	0.0	0.019	0.033	29.80	3.70	358.90	33.70	8.05	8.92	0.177
1.10	1.00	0.0	83.8	0.075	0.240	41.00	15.00	373.90	35.11	2.73	16.00	0.179
1.10	1.00	20.9	0.0	0.019	0.039	25.40	3.50	377.40	35.44	7.26	11.14	0.168

TABLE A11 (CONTINUED)

RESULTS OF RUN 1DT11
[0.20 HCPV CO2-N2 @ 1.00 MPa (0.089 g-mol) 4:1 WAG,10 Slugs, DEAD OIL] LC

Porosity [%] = 35.8
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.31

Pore Volume [cm3] = 1112.0
Initial Oil Saturation [%] = 94.1
Hydrocarbon Pore Volume [cm3] = 1065.0
Carbon Dioxide Retention [%inj] = 8.87

Connate Water Saturation [%] = 5.9
Molar Density @ atm. [kmol/m3] = 0.04160
Absolute Permeability [darcies] = 11.8900
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	83.7	0.075	0.230	43.00	15.00	392.40	36.85	2.87	15.33	0.179
1.10	1.00	20.9	0.0	0.019	0.068	29.90	3.60	396.00	37.18	8.31	18.89	0.172
1.10	1.00	0.0	85.2	0.077	0.329	45.50	11.50	407.50	38.26	3.96	28.61	0.135
1.10	1.00	0.0	252.6	0.227	0.183	190.00	54.00	461.50	43.33	3.52	3.39	0.214
1.10	1.00	0.0	251.9	0.227	0.110	210.00	35.00	496.50	46.62	6.00	3.14	0.139
1.10	1.00	0.0	244.3	0.220	0.132	218.00	27.50	524.00	49.20	7.93	4.80	0.113
1.10	1.00	0.0	247.8	0.223	0.139	234.00	11.00	535.00	50.23	21.27	12.64	0.044
0.10	0.10	0.0	0.0	0.000	0.284	139.00	33.00	578.00	54.27	4.21	8.61	

TABLE A12

RESULTS OF RUN 1DT12
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.091 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.8
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.45

Pore Volume [cm3] = 1112.0
Initial Oil Saturation [%] = 95.8
Hydrocarbon Pore Volume [cm3] = 1065.0
Carbon Dioxide Retention [%inj] = 3.06

Connate Water Saturation [%] = 4.2
Molar Density @ atm. [kmol/m3] = 0.04159
Absolute Permeability [darcies] = 11.4300
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	21.3	0.0	0.019	0.000	0.00	3.00	3.00	0.28	0.00	0.00	0.141
1.30	1.00	0.0	85.2	0.077	0.003	0.00	83.70	86.70	8.14	0.00	0.04	0.983
1.20	1.00	21.3	0.0	0.019	0.000	0.00	19.50	106.20	9.97	0.00	0.00	0.914
1.10	1.00	0.0	85.2	0.077	0.000	2.00	68.80	175.00	16.43	0.03	0.00	0.808
1.20	1.00	21.3	0.0	0.019	0.000	6.00	17.00	192.00	18.03	0.35	0.00	0.797
1.10	1.00	0.0	85.4	0.077	0.000	26.40	41.60	233.60	21.93	0.63	0.00	0.487
1.20	1.00	21.3	0.0	0.019	0.001	16.20	13.30	246.90	23.18	1.22	0.08	0.624
1.10	1.00	0.0	85.2	0.077	0.054	36.50	29.50	276.40	25.95	1.24	1.83	0.346
1.20	1.00	21.3	0.0	0.019	0.005	16.50	9.50	285.90	26.85	1.74	0.53	0.445
1.10	1.00	0.0	85.2	0.077	0.112	36.80	26.70	312.60	29.35	1.38	4.19	0.313
1.10	1.00	21.3	0.0	0.019	0.004	17.30	5.60	318.20	29.88	3.09	0.71	0.263
1.10	1.00	0.0	85.2	0.077	0.119	50.00	16.50	334.70	31.43	3.03	7.21	0.194
1.20	1.00	21.3	0.0	0.019	0.013	19.00	4.00	338.70	31.80	4.75	3.25	0.188
1.10	1.00	0.0	85.2	0.077	0.107	51.00	17.00	355.70	33.40	3.00	6.29	0.200
1.10	1.00	21.3	0.0	0.019	0.030	23.50	6.00	361.70	33.96	3.92	5.00	0.281
1.10	1.00	0.0	85.2	0.077	0.141	46.00	18.50	380.20	35.70	2.49	7.62	0.217
1.10	1.00	21.3	0.0	0.019	0.029	23.70	2.80	383.00	35.96	8.46	10.36	0.131

TABLE A12 (CONTINUED)

RESULTS OF RUN 1DT12
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.091 g-mol) 4:1 WAG, 10 Slugs, DEAD OIL]

Porosity [%] = 35.8
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.45

Pore Volume [cm3] = 1112.0
Initial Oil Saturation [%] = 95.8
Hydrocarbon Pore Volume [cm3] = 1065.0
Carbon Dioxide Retention [%inj] = 3.06

Connate Water Saturation [%] = 4.2
Molar Density @ atm. [kmol/m3] = 0.04159
Absolute Permeability [darcies] = 11.4300
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	85.2	0.077	0.153	45.00	17.60	400.60	37.61	2.56	8.69	0.207
1.10	1.00	21.3	0.0	0.019	0.032	27.40	3.30	403.90	37.92	8.30	9.70	0.155
1.10	1.00	0.0	85.2	0.077	0.233	41.30	15.70	419.60	39.40	2.63	14.84	0.184
1.10	1.00	0.0	253.9	0.228	0.200	193.00	54.00	473.60	44.47	3.57	3.70	0.213
1.10	1.00	0.0	254.3	0.229	0.198	214.00	34.00	507.60	47.66	6.29	5.82	0.134
1.10	1.00	0.0	250.5	0.225	0.140	228.00	24.00	531.60	49.92	9.50	5.83	0.096
1.10	1.00	0.0	253.6	0.228	0.222	223.00	22.00	553.60	51.98	10.14	10.09	0.087
1.10	1.00	0.0	250.5	0.225	0.146	239.00	11.00	564.60	53.01	21.73	13.27	0.044
0.01	0.01	0.0	0.0	0.000	0.560	137.00	15.00	559.13	52.50	9.13	37.33	

TABLE A13

RESULTS OF RUN 1DT13

[0.20 HCPV CO2-N2 @ 1.0 MPa (0.089 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.2
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.72

Pore Volume [cm3] = 1095.0
Initial Oil Saturation [%] = 96.2
Hydrocarbon Pore Volume [cm3] = 1052.9
Carbon Dioxide Retention [%inj] = 1.36

Connate Water Saturation [%] = 3.8
Molar Density @ atm. [kmol/m3] = 0.04158
Absolute Permeability [darcies] = 11.0900
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	21.1	0.0	0.019	0.000	0.00	0.50	0.50	0.05	0.00	0.00	0.024
1.30	1.00	0.0	84.2	0.077	0.000	1.20	82.00	82.50	7.84	0.01	0.00	0.974
1.20	1.00	21.1	0.0	0.019	0.000	0.00	15.80	98.30	9.34	0.00	0.00	0.749
1.20	1.00	0.0	84.2	0.077	0.000	2.50	71.40	169.70	16.12	0.04	0.00	0.848
1.20	1.00	21.1	0.0	0.019	0.000	18.60	11.40	181.10	17.20	1.63	0.00	0.540
1.10	1.00	0.0	84.2	0.077	0.070	28.00	31.30	212.40	20.17	0.89	2.24	0.372
1.20	1.00	21.1	0.0	0.019	0.003	20.70	9.30	221.70	21.06	2.23	0.32	0.441
1.20	1.00	0.0	84.2	0.077	0.058	37.00	20.30	242.00	22.98	1.82	2.86	0.241
1.20	1.00	21.1	0.0	0.019	0.011	18.30	2.30	244.30	23.20	7.96	4.78	0.109
1.10	1.00	0.0	84.3	0.077	0.054	34.80	26.70	271.00	25.74	1.30	2.02	0.317
1.10	1.00	21.1	0.0	0.019	0.016	22.00	3.00	274.00	26.02	7.33	5.33	0.142
1.10	1.00	0.0	84.2	0.077	0.100	34.50	22.00	296.00	28.11	1.57	4.55	0.261
1.10	1.00	21.1	0.0	0.019	0.005	7.80	2.00	298.00	28.30	3.90	2.50	0.095
1.10	1.00	0.0	84.8	0.077	0.020	59.40	22.10	320.10	30.40	2.69	0.90	0.261
1.10	1.00	21.1	0.0	0.019	0.017	23.80	1.50	321.60	30.54	15.87	11.33	0.071
1.10	1.00	0.0	84.2	0.077	0.124	45.50	11.00	332.60	31.59	4.14	11.27	0.131
1.10	1.00	21.1	0.0	0.019	0.036	28.00	2.00	334.60	31.78	14.00	18.00	0.095

TABLE A13 (CONTINUED)

RESULTS OF RUN 1DT13

[0.20 HCPV CO2-N2 @ 1.0 MPa (0.089 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.2
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.72

Pore Volume [cm3] = 1095.0
Initial Oil Saturation [%] = 96.2
Hydrocarbon Pore Volume [cm3] = 1052.9
Carbon Dioxide Retention [%inj] = 1.36

Connate Water Saturation [%] = 3.8
Molar Density @ atm. [kmol/m3] = 0.04158
Absolute Permeability [darcies] = 11.0900
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	84.2	0.077	0.211	48.50	9.10	343.70	32.64	5.33	23.19	0.108
1.20	1.00	21.1	0.0	0.019	0.032	22.00	1.50	345.20	32.79	14.67	21.33	0.071
1.10	1.00	0.0	84.3	0.077	0.160	45.80	11.20	356.40	33.85	4.09	14.29	0.133
1.10	1.00	0.0	251.3	0.230	0.075	179.00	71.00	427.40	40.59	2.52	1.06	0.283
1.10	1.00	0.0	260.6	0.238	0.112	221.00	34.00	461.40	43.82	6.50	3.29	0.130
1.10	1.00	0.0	252.3	0.230	0.127	224.00	25.00	486.40	46.20	8.96	5.08	0.099
1.10	1.00	0.0	250.9	0.229	0.134	227.00	22.00	508.40	48.29	10.32	6.09	0.088
1.10	1.00	0.0	250.8	0.229	0.107	237.00	11.00	519.40	49.33	21.55	9.73	0.044
0.01	0.01	0.0	0.0	0.000	0.281	113.00	21.50	540.90	51.37	5.26	13.07	

TABLE A14

RESULTS OF RUN 1DT14
[0.20 HCPV CO2-N2 @ 1.2 MPa (0.111 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.9
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.56

Pore Volume [cm3] = 1116.0
Initial Oil Saturation [%] = 95.5
Hydrocarbon Pore Volume [cm3] = 1065.9
Carbon Dioxide Retention [%inj] = 50.67

Connate Water Saturation [%] = 4.5
Molar Density @ atm. [kmol/m3] = 0.04162
Absolute Permeability [darcies] = 11.6900
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.30	1.20	25.8	0.0	0.023	0.012	0.00	1.50	1.50	0.14	0.00	8.00	0.058
1.40	1.20	0.0	85.2	0.076	0.005	0.50	83.80	85.30	8.00	0.01	0.06	0.983
1.40	1.20	25.8	0.0	0.023	0.000	0.00	14.50	99.80	9.36	0.00	0.00	0.563
1.40	1.20	0.0	85.3	0.076	0.000	0.00	76.90	176.70	16.58	0.00	0.00	0.902
1.40	1.20	25.8	0.0	0.023	0.000	1.00	17.90	194.60	18.26	0.06	0.00	0.695
1.30	1.20	0.0	85.3	0.076	0.065	25.00	49.00	243.60	22.85	0.51	1.33	0.575
1.30	1.20	25.8	0.0	0.023	0.005	8.90	6.10	249.70	23.43	1.46	0.82	0.237
1.30	1.20	0.0	85.3	0.076	0.092	41.00	30.50	280.20	26.29	1.34	3.02	0.358
1.30	1.20	25.8	0.0	0.023	0.007	16.00	3.50	283.70	26.62	4.57	2.00	0.136
1.30	1.20	0.0	85.3	0.076	0.192	39.70	25.30	309.00	28.99	1.57	7.59	0.297
1.30	1.20	25.8	0.0	0.023	0.003	12.20	1.80	310.80	29.16	6.78	1.67	0.070
1.30	1.20	0.0	85.3	0.076	0.099	55.00	17.00	327.80	30.75	3.24	5.82	0.199
1.30	1.20	25.8	0.0	0.023	0.006	14.00	2.00	329.80	30.94	7.00	3.00	0.078
1.30	1.20	0.0	85.3	0.076	0.114	54.00	19.00	348.80	32.72	2.84	6.00	0.223
1.30	1.20	25.8	0.0	0.023	0.008	12.00	2.00	350.80	32.91	6.00	4.00	0.078
1.30	1.20	0.0	85.3	0.076	0.097	52.50	21.50	372.30	34.93	2.44	4.51	0.252
1.30	1.20	25.8	0.0	0.023	0.007	19.50	3.00	375.30	35.21	6.50	2.33	0.116

TABLE A14 (CONTINUED)

RESULTS OF RUN 1DT14
[0.20 HCPV CO2-N2 @ 1.2 MPa (0.111 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.9
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.56

Pore Volume [cm3] = 1116.0
Initial Oil Saturation [%] = 95.5
Hydrocarbon Pore Volume [cm3] = 1065.9
Carbon Dioxide Retention [%inj] = 50.67

Connate Water Saturation [%] = 4.5
Molar Density @ atm. [kmol/m3] = 0.04162
Absolute Permeability [darcies] = 11.6900
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.30	1.20	0.0	85.3	0.076	0.194	50.00	17.00	392.30	36.80	2.94	11.41	0.199
1.30	1.20	25.8	0.0	0.023	0.021	30.00	4.00	396.30	37.18	7.50	5.25	0.155
1.30	1.20	0.0	85.3	0.076	0.339	40.00	15.20	411.50	38.61	2.63	22.30	0.178
1.30	1.20	0.0	252.8	0.227	0.120	183.00	67.00	478.50	44.89	2.73	1.79	0.265
1.30	1.20	0.0	261.4	0.234	0.108	198.00	60.00	538.50	50.52	3.30	1.80	0.230
1.30	1.20	0.0	251.9	0.226	0.089	215.00	36.00	574.50	53.90	5.97	2.47	0.143
1.30	1.20	0.0	251.4	0.225	0.062	220.00	31.00	605.50	56.81	7.10	2.00	0.123
1.30	1.20	0.0	251.6	0.225	0.049	234.00	17.00	622.50	58.40	13.76	2.88	0.068
1.30	1.20	0.0	249.4	0.223	0.030	238.50	11.50	634.00	59.48	20.74	2.61	0.046
0.01	0.01	0.0	0.0	0.000	0.059	81.00	16.00	650.00	60.98	5.06	3.69	

TABLE A15

RESULTS OF RUN 1DT15
[0.20 HCPV CO2-N2 @ 1.35 MPa (0.122 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.4
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.46

Pore Volume [cm3] = 1101.5
Initial Oil Saturation [%] = 95.1
Hydrocarbon Pore Volume [cm3] = 1051.5
Carbon Dioxide Retention [%inj] = 51.17

Connate Water Saturation [%] = 4.9
Molar Density @ atm. [kmol/m3] = 0.04159
Absolute Permeability [darcies] = 10.7800
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.42	1.35	21.0	0.0	0.019	0.000	0.00	3.00	3.00	0.29	0.00	0.00	0.143
1.65	1.35	0.0	84.1	0.076	0.003	0.00	83.70	86.70	8.25	0.00	0.04	0.995
1.50	1.35	21.0	0.0	0.019	0.000	0.00	9.50	96.20	9.15	0.00	0.00	0.452
1.55	1.35	0.0	84.1	0.076	0.000	1.00	78.70	174.90	16.63	0.01	0.00	0.936
1.50	1.35	21.0	0.0	0.019	0.000	4.00	13.80	188.70	17.95	0.29	0.00	0.657
1.50	1.35	0.0	84.1	0.076	0.000	35.00	37.80	226.50	21.54	0.93	0.00	0.449
1.42	1.35	21.0	0.0	0.019	0.001	11.50	5.40	231.90	22.05	2.13	0.19	0.257
1.45	1.35	0.0	84.1	0.076	0.000	47.00	25.00	256.90	24.43	1.88	0.00	0.297
1.45	1.35	21.0	0.0	0.019	0.002	14.00	5.50	262.40	24.95	2.55	0.36	0.262
1.45	1.35	0.0	84.1	0.076	0.002	48.40	23.10	285.50	27.15	2.10	0.09	0.275
1.45	1.35	21.0	0.0	0.019	0.002	12.80	4.80	290.30	27.61	2.67	0.42	0.229
1.45	1.35	0.0	84.1	0.076	0.059	46.50	24.20	314.50	29.91	1.92	2.44	0.288
1.40	1.35	21.0	0.0	0.019	0.007	12.90	3.60	318.10	30.25	3.58	1.94	0.171
1.42	1.35	0.0	88.5	0.080	0.044	52.00	22.50	340.60	32.39	2.31	1.96	0.254
1.42	1.35	21.0	0.0	0.019	0.008	10.50	2.50	343.10	32.63	4.20	3.20	0.119
1.50	1.35	0.0	84.1	0.076	0.021	59.50	20.30	363.40	34.56	2.93	1.03	0.241
1.48	1.35	21.0	0.0	0.019	0.021	20.50	3.50	366.90	34.89	5.86	6.00	0.167

TABLE A15 (CONTINUED)

RESULTS OF RUN 1DT15
[0.20 HCPV CO2-N2 @ 1.35 MPa (0.122 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.4
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.46

Pore Volume [cm3] = 1101.5
Initial Oil Saturation [%] = 95.1
Hydrocarbon Pore Volume [cm3] = 1051.5
Carbon Dioxide Retention [%inj] = 51.17

Connate Water Saturation [%] = 4.9
Molar Density @ atm. [kmol/m3] = 0.04159
Absolute Permeability [darcies] = 10.7800
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.42	1.35	0.0	84.1	0.076	0.303	46.00	13.50	380.40	36.18	3.41	22.44	0.160
1.45	1.35	21.0	0.0	0.019	0.012	14.00	2.20	382.60	36.39	6.36	5.45	0.105
1.50	1.35	0.0	84.1	0.076	0.157	54.70	15.90	398.50	37.90	3.44	9.87	0.189
1.50	1.35	0.0	250.6	0.228	0.127	193.00	54.00	452.50	43.03	3.57	2.35	0.215
1.50	1.35	0.0	247.4	0.225	0.134	218.00	28.00	480.50	45.70	7.79	4.79	0.113
1.50	1.35	0.0	247.0	0.224	0.124	221.00	24.00	504.50	47.98	9.21	5.17	0.097
1.50	1.35	0.0	250.2	0.227	0.094	227.00	19.00	523.50	49.79	11.95	4.95	0.076
1.50	1.35	0.0	247.7	0.225	0.069	234.00	14.00	537.50	51.12	16.71	4.93	0.057
1.50	1.35	0.0	251.9	0.229	0.057	239.00	15.50	553.00	52.59	15.42	3.68	0.062
0.01	0.01	0.0	0.0	0.000	0.347	116.00	45.00	598.00	56.87	2.58	7.71	

TABLE A16

RESULTS OF RUN 1DT16
[0.20 HCPV CO2-N2 @ 1.44 MPa (0.130 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.5
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.93

Pore Volume [cm3] = 1104.0
Initial Oil Saturation [%] = 95.1
Hydrocarbon Pore Volume [cm3] = 1050.1
Carbon Dioxide Retention [%inj] = 32.96

Connate Water Saturation [%] = 4.9
Molar Density @ atm. [kmol/m3] = 0.04158
Absolute Permeability [darcies] = 10.0200
Average Flow Velocity [m/d] ≈ 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.46	1.44	21.0	0.0	0.019	0.003	0.00	3.60	3.60	0.34	0.00	0.83	0.172
1.74	1.44	0.0	84.0	0.076	0.003	1.00	81.00	84.60	8.06	0.01	0.04	0.964
1.66	1.44	21.0	0.0	0.019	0.000	0.00	16.60	101.20	9.64	0.00	0.00	0.791
1.63	1.44	0.0	84.0	0.076	0.000	6.90	65.90	167.10	15.91	0.10	0.00	0.784
1.62	1.44	21.0	0.0	0.019	0.001	7.80	12.70	179.80	17.12	0.61	0.08	0.605
1.62	1.44	0.0	84.0	0.076	0.001	30.60	39.40	219.20	20.87	0.78	0.03	0.469
1.52	1.44	21.0	0.0	0.019	0.001	8.30	7.80	227.00	21.62	1.06	0.13	0.372
1.58	1.44	0.0	84.0	0.076	0.005	37.20	36.30	263.30	25.07	1.02	0.14	0.432
1.58	1.44	21.0	0.0	0.019	0.002	9.50	6.10	269.40	25.65	1.56	0.33	0.291
1.54	1.44	0.0	84.0	0.076	0.011	49.40	25.60	295.00	28.09	1.93	0.43	0.305
1.56	1.44	21.0	0.0	0.019	0.005	15.00	4.80	299.80	28.55	3.12	1.04	0.229
1.62	1.44	0.0	84.0	0.076	0.155	46.50	19.10	318.90	30.37	2.43	8.12	0.227
1.54	1.44	21.0	0.0	0.019	0.005	18.50	3.10	322.00	30.66	5.97	1.61	0.148
1.54	1.44	0.0	84.0	0.076	0.137	57.00	12.00	334.00	31.81	4.75	11.42	0.143
1.58	1.44	21.0	0.0	0.019	0.007	13.20	3.00	337.00	32.09	4.40	2.33	0.143
1.56	1.44	0.0	84.0	0.076	0.115	54.40	16.60	353.60	33.67	3.28	6.93	0.198
1.50	1.44	21.0	0.0	0.019	0.008	13.60	2.90	356.50	33.95	4.69	2.76	0.138

TABLE A16 (CONTINUED)

RESULTS OF RUN 1DT16
[0.20 HCPV CO2-N2 @ 1.44 MPa (0.130 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.5
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.93

Pore Volume [cm3] = 1104.0
Initial Oil Saturation [%] = 95.1
Hydrocarbon Pore Volume [cm3] = 1050.1
Carbon Dioxide Retention [%inj] = 32.96

Connate Water Saturation [%] = 4.9
Molar Density @ atm. [kmol/m3] = 0.04158
Absolute Permeability [darcies] = 10.0200
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.56	1.44	0.0	84.1	0.076	0.028	59.40	16.70	373.20	35.54	3.56	1.68	0.199
1.50	1.44	21.0	0.0	0.019	0.007	19.20	3.50	376.70	35.87	5.49	2.00	0.167
1.56	1.44	0.0	84.0	0.076	0.209	46.30	16.70	393.40	37.46	2.77	12.51	0.199
1.10	1.00	0.0	254.0	0.230	0.157	190.00	58.00	451.40	42.99	3.28	2.71	0.228
1.10	1.00	0.0	251.3	0.228	0.229	207.00	39.00	490.40	46.70	5.31	5.87	0.155
1.10	1.00	0.0	250.2	0.227	0.254	212.00	35.50	525.90	50.08	5.97	7.15	0.142
1.10	1.00	0.0	250.6	0.227	0.214	233.00	14.50	540.40	51.46	16.07	14.76	0.058
1.10	1.00	0.0	247.6	0.224	0.122	242.00	8.00	548.40	52.22	30.25	15.25	0.032
0.01	0.01	0.0	0.0	0.000	0.681	116.00	45.00	593.40	56.51	2.58	15.13	

TABLE A17

RESULTS OF RUN 1DT17

[0.24 HCPV CO2-N2 @ 1.00 MPa (0.106 g-mol) 4:1 WAG, 10 Slugs, DEAD OIL]

Porosity [%] = 35.6
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.40

Pore Volume [cm3] = 1107.0
Initial Oil Saturation [%] = 95.6
Hydrocarbon Pore Volume [cm3] = 1058.2
Carbon Dioxide Retention [%inj] = 31.03

Connate Water Saturation [%] = 4.4
Molar Density @ atm. [kmol/m3] = 0.04162
Absolute Permeability [darcies] = 10.2400
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	24.9	0.0	0.022	0.000	0.00	2.50	2.50	0.24	0.00	0.00	0.100
1.10	1.00	0.0	100.6	0.091	0.005	0.00	97.80	100.30	9.48	0.00	0.05	0.972
1.20	1.00	24.9	0.0	0.022	0.000	0.00	18.70	119.00	11.25	0.00	0.00	0.751
1.10	1.00	0.0	100.3	0.091	0.000	1.00	87.50	206.50	19.51	0.01	0.00	0.872
1.10	1.00	24.9	0.0	0.022	0.000	11.00	23.70	230.20	21.75	0.46	0.00	0.952
1.10	1.00	0.0	99.6	0.090	0.012	30.50	39.50	269.70	25.49	0.77	0.30	0.397
1.10	1.00	24.9	0.0	0.022	0.006	22.00	12.50	282.20	26.67	1.76	0.48	0.502
1.10	1.00	0.0	99.6	0.090	0.026	42.00	23.00	305.20	28.84	1.83	1.13	0.231
1.10	1.00	24.9	0.0	0.022	0.013	28.10	4.90	310.10	29.30	5.73	2.65	0.197
1.10	1.00	0.0	99.6	0.090	0.041	56.00	15.00	325.10	30.72	3.73	2.73	0.151
1.10	1.00	24.9	0.0	0.022	0.010	31.20	3.50	328.60	31.05	8.91	2.86	0.141
1.10	1.00	0.0	99.6	0.090	0.030	53.30	13.70	342.30	32.35	3.89	2.19	0.137
1.10	1.00	24.9	0.0	0.022	0.013	29.90	5.10	347.40	32.83	5.86	2.55	0.205
1.10	1.00	0.0	99.6	0.090	0.094	56.00	13.80	361.20	34.13	4.06	6.81	0.139
1.10	1.00	24.9	0.0	0.022	0.018	35.30	3.70	364.90	34.48	9.54	4.86	0.149
1.10	1.00	0.0	99.6	0.090	0.119	54.00	12.00	376.90	35.62	4.50	9.92	0.120
1.10	1.00	24.9	0.0	0.022	0.030	32.80	3.70	380.60	35.97	8.86	8.11	0.149

TABLE A17 (CONTINUED)

RESULTS OF RUN 1DT17
[0.24 HCPV CO2-N2 @ 1.00 MPa (0.106 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.6
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.40

Pore Volume [cm3] = 1107.0
Initial Oil Saturation [%] = 95.6
Hydrocarbon Pore Volume [cm3] = 1058.2
Carbon Dioxide Retention [%inj] = 31.03

Connate Water Saturation [%] = 4.4
Molar Density @ atm. [kmol/m3] = 0.04162
Absolute Permeability [darcies] = 10.2400
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	99.6	0.090	0.114	54.00	13.00	393.60	37.20	4.15	8.77	0.131
1.10	1.00	24.9	0.0	0.022	0.040	32.30	3.20	396.80	37.50	10.09	12.50	0.129
1.10	1.00	0.0	99.6	0.090	0.126	51.00	19.00	415.80	39.29	2.68	6.63	0.191
1.10	1.00	0.0	247.4	0.223	0.238	201.00	41.00	456.80	43.17	4.90	5.80	0.166
1.10	1.00	0.0	251.4	0.227	0.338	220.00	27.00	483.80	45.72	8.15	12.52	0.107
1.10	1.00	0.0	250.2	0.226	0.173	232.50	16.50	500.30	47.28	14.09	10.48	0.066
1.10	1.00	0.0	255.5	0.231	0.152	245.00	10.00	510.30	48.22	24.50	15.20	0.039
0.01	0.01	0.0	0.0	0.000	0.314	124.00	26.00	546.88	51.68	4.77	12.08	

TABLE A18

RESULTS OF RUN 1DT18

[0.27 HCPV CO2-N2 @ 1.0 MPa (0.119 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.6
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 6.43

Pore Volume [cm3] = 1108.0
Initial Oil Saturation [%] = 95.5
Hydrocarbon Pore Volume [cm3] = 1058.2
Carbon Dioxide Retention [%inj] = 22.16

Connate Water Saturation [%] = 4.5
Molar Density @ atm. [kmol/m3] = 0.04159
Absolute Permeability [darcies] = 11.2800
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	28.0	0.0	0.025	0.000	0.00	3.50	3.50	0.33	0.00	0.00	0.125
1.30	1.00	0.0	111.8	0.101	0.000	2.00	100.00	103.50	9.78	0.02	0.00	0.895
1.20	1.00	28.0	0.0	0.025	0.001	1.50	19.50	123.00	11.62	0.08	0.05	0.697
1.20	1.00	0.0	111.8	0.101	0.001	17.90	78.10	201.10	19.00	0.23	0.01	0.699
1.20	1.00	28.0	0.0	0.025	0.000	21.60	18.20	219.30	20.72	1.19	0.00	0.650
1.10	1.00	0.0	111.8	0.101	0.203	49.00	28.00	247.30	23.37	1.75	7.25	0.250
1.10	1.00	28.0	0.0	0.025	0.005	26.10	6.40	253.70	23.97	4.08	0.78	0.229
1.10	1.00	0.0	111.8	0.101	0.203	55.00	27.00	280.70	26.53	2.04	7.52	0.242
1.30	1.00	28.0	0.0	0.025	0.009	31.80	6.70	287.40	27.16	4.75	1.34	0.239
1.10	1.00	0.0	111.8	0.101	0.223	48.40	26.60	314.00	29.67	1.82	8.38	0.238
1.20	1.00	28.0	0.0	0.025	0.010	28.80	5.70	319.70	30.21	5.05	1.75	0.204
1.20	1.00	0.0	111.8	0.101	0.156	61.40	19.20	338.90	32.03	3.20	8.13	0.172
1.20	1.00	28.0	0.0	0.025	0.027	33.30	7.40	346.30	32.73	4.50	3.65	0.264
1.20	1.00	0.0	111.9	0.101	0.150	57.50	17.30	363.60	34.36	3.32	8.67	0.155
1.20	1.00	28.0	0.0	0.025	0.035	35.30	6.20	369.80	34.95	5.69	5.65	0.222
1.10	1.00	0.0	111.8	0.101	0.208	56.50	18.50	388.30	36.69	3.05	11.24	0.165
1.20	1.00	28.0	0.0	0.025	0.045	31.30	5.70	394.00	37.23	5.49	7.89	0.204

TABLE A18 (CONTINUED)

RESULTS OF RUN 1DT18
[0.27 HCPV CO2-N2 @ 1.0 MPa (0.119 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.6
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 6.43

Pore Volume [cm3] = 1108.0
Initial Oil Saturation [%] = 95.5
Hydrocarbon Pore Volume [cm3] = 1058.2
Carbon Dioxide Retention [%inj] = 22.16

Connate Water Saturation [%] = 4.5
Molar Density @ atm. [kmol/m3] = 0.04159
Absolute Permeability [darcies] = 11.2800
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	111.8	0.101	0.205	58.20	17.60	411.60	38.90	3.31	11.65	0.157
1.20	1.00	28.0	0.0	0.025	0.026	31.50	2.50	414.10	39.13	12.60	10.40	0.089
1.20	1.00	0.0	112.0	0.101	0.271	68.50	16.20	430.30	40.66	4.23	16.73	0.145
1.10	1.00	0.0	250.6	0.226	0.158	218.50	27.50	457.80	43.26	7.95	5.75	0.110
1.10	1.00	0.0	250.7	0.226	0.142	226.00	21.00	478.80	45.25	10.76	6.76	0.084
1.10	1.00	0.0	250.7	0.226	0.140	234.00	17.00	495.80	46.85	13.76	8.24	0.068
1.10	1.00	0.0	250.8	0.226	0.122	234.00	15.00	510.80	48.27	15.60	8.13	0.060
1.10	1.00	0.0	250.8	0.226	0.077	236.50	13.50	524.30	49.55	17.52	5.70	0.054
1.10	1.00	0.0	251.0	0.227	0.062	236.00	11.00	535.30	50.59	21.45	5.64	0.044
0.01	0.01	0.0	0.0	0.000	0.255	109.00	11.00	546.30	51.63	9.91	23.18	

TABLE A19

RESULTS OF RUN 1DT19
[0.29 HCPV CO2-N2 @ 1.0 MPa (0.129 g-mol) 4:1 WAG, 10 Slugs, DEAD OIL]

Porosity [%] = 35.9
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 6.42

Pore Volume [cm3] = 1116.5
Initial Oil Saturation [%] = 95.2
Hydrocarbon Pore Volume [cm3] = 1063.0
Carbon Dioxide Retention [%inj] = 4.06

Connate Water Saturation [%] = 4.8
Molar Density @ atm. [kmol/m3] = 0.04158
Absolute Permeability [darcies] = 10.9900
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	30.3	0.0	0.027	0.000	0.00	0.25	0.25	0.02	0.00	0.00	0.008
1.30	1.00	0.0	121.5	0.109	0.006	1.00	119.00	119.25	11.22	0.01	0.05	0.980
1.20	1.00	30.3	0.0	0.027	0.001	0.20	19.40	138.65	13.04	0.01	0.05	0.640
1.10	1.00	0.0	121.5	0.109	0.001	36.00	76.50	215.15	20.24	0.47	0.01	0.630
1.00	1.00	30.3	0.0	0.027	0.001	2.40	3.20	218.35	20.54	0.75	0.31	0.106
1.10	1.00	0.0	121.5	0.109	0.197	71.00	47.00	265.35	24.96	1.51	4.19	0.387
1.10	1.00	30.3	0.0	0.027	0.001	2.50	2.10	267.45	25.16	1.19	0.48	0.069
1.10	1.00	0.0	121.5	0.109	0.219	73.00	37.00	304.45	28.64	1.97	5.92	0.305
1.10	1.00	30.3	0.0	0.027	0.012	1.50	1.50	305.95	28.78	1.00	8.00	0.049
1.10	1.00	0.0	121.5	0.109	0.304	91.00	28.50	334.45	31.46	3.19	10.67	0.235
1.10	1.00	30.3	0.0	0.027	0.011	6.50	1.50	335.95	31.60	4.33	7.33	0.049
1.10	1.00	0.0	121.5	0.109	0.305	89.00	30.00	365.95	34.43	2.97	10.17	0.247
1.10	1.00	30.3	0.0	0.027	0.030	9.00	2.00	367.95	34.61	4.50	15.00	0.066
1.10	1.00	0.0	121.5	0.109	0.309	90.50	22.70	390.65	36.75	3.99	13.61	0.187
1.10	1.00	30.3	0.0	0.027	0.029	7.00	1.50	392.15	36.89	4.67	19.33	0.049
1.10	1.00	0.0	121.5	0.109	0.326	98.00	18.50	410.65	38.63	5.30	17.62	0.152
1.10	1.00	30.3	0.0	0.027	0.019	6.70	1.40	412.05	38.76	4.79	13.57	0.046

TABLE A19 (CONTINUED)

RESULTS OF RUN 1DT19

[0.29 HCPV CO2-N2 @ 1.0 MPa (0.129 g-mol) 4:1 WAG, 10 Slugs, DEAD OIL]

Porosity [%] = 35.9
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 6.42

Pore Volume [cm3] = 1116.5
Initial Oil Saturation [%] = 95.2
Hydrocarbon Pore Volume [cm3] = 1063.0
Carbon Dioxide Retention [%inj] = 4.06

Connate Water Saturation [%] = 4.8
Molar Density @ atm. [kmol/m3] = 0.04158
Absolute Permeability [darcies] = 10.9900
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	121.5	0.109	0.335	103.00	17.00	429.05	40.36	6.06	19.71	0.140
1.10	1.00	30.3	0.0	0.027	0.033	20.20	1.80	430.85	40.53	11.22	18.33	0.059
1.10	1.00	0.0	118.8	0.106	0.293	81.00	16.50	447.35	42.08	4.91	17.76	0.139
1.10	1.00	0.0	249.1	0.223	0.237	212.00	38.50	485.85	45.71	5.51	6.16	0.155
1.10	1.00	0.0	245.8	0.220	0.245	225.00	25.00	510.85	48.06	9.00	9.80	0.102
1.10	1.00	0.0	249.5	0.223	0.241	230.00	12.00	522.85	49.19	19.17	20.08	0.048
0.01	0.01	0.0	0.0	0.000	0.202	78.50	22.50	545.35	51.30	3.49	8.98	

TABLE A20

RESULTS OF RUN 1DT20

[0.50 HCPV CO2-N2 @ 1.0 MPa (0.227 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.6
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 10.27

Pore Volume [cm3] = 1107.0
Initial Oil Saturation [%] = 95.6
Hydrocarbon Pore Volume [cm3] = 1058.0
Carbon Dioxide Retention [%inj] = 38.23

Connate Water Saturation [%] = 4.4
Molar Density @ atm. [kmol/m3] = 0.04164
Absolute Permeability [darcies] = 8.8900
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.20	1.00	52.9	0.0	0.048	0.001	0.50	25.00	25.00	2.36	0.02	0.04	0.473
1.20	1.00	0.0	211.6	0.191	0.000	5.00	185.00	210.00	19.85	0.03	0.00	0.874
1.10	1.00	52.9	0.0	0.048	0.002	20.30	30.70	240.70	22.75	0.66	0.07	0.580
1.10	1.00	0.0	211.6	0.191	0.003	99.00	68.00	308.70	29.18	1.46	0.04	0.321
1.10	1.00	52.9	0.0	0.048	0.005	41.40	10.90	319.60	30.21	3.80	0.46	0.206
1.10	1.00	0.0	211.6	0.191	0.022	133.00	27.50	347.10	32.81	4.84	0.80	0.130
1.10	1.00	52.9	0.0	0.048	0.008	45.50	6.00	353.10	33.37	7.58	1.33	0.113
1.10	1.00	0.0	211.6	0.191	0.054	133.50	30.00	383.10	36.21	4.45	1.80	0.142
1.10	1.00	52.9	0.0	0.048	0.026	45.00	7.50	390.60	36.92	6.00	3.47	0.142
1.10	1.00	0.0	211.6	0.191	0.099	122.70	40.30	430.90	40.73	3.04	2.46	0.190
1.10	1.00	52.9	0.0	0.048	0.079	42.00	6.00	436.90	41.29	7.00	13.17	0.113
1.10	1.00	0.0	211.6	0.191	0.206	145.00	24.00	460.90	43.56	6.04	8.58	0.113
1.10	1.00	52.9	0.0	0.048	0.079	45.50	4.50	465.40	43.99	10.11	17.56	0.085
1.00	1.00	0.0	211.6	0.191	0.340	145.00	23.00	488.40	46.16	6.30	14.78	0.109
1.10	1.00	52.9	0.0	0.048	0.078	42.00	3.60	492.00	46.50	11.67	21.67	0.068
1.10	1.00	0.0	211.6	0.191	0.340	147.00	20.00	512.00	48.39	7.35	17.00	0.095
1.10	1.00	52.9	0.0	0.048	0.075	51.00	2.00	514.00	48.58	25.50	37.50	0.038

TABLE A20 (CONTINUED)

RESULTS OF RUN 1DT20
[0.50 HCPV CO2-N2 @ 1.0 MPa (0.227 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.6
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 10.27

Pore Volume [cm3] = 1107.0
Initial Oil Saturation [%] = 95.6
Hydrocarbon Pore Volume [cm3] = 1058.0
Carbon Dioxide Retention [%inj] = 38.23

Connate Water Saturation [%] = 4.4
Molar Density @ atm. [kmol/m3] = 0.04164
Absolute Permeability [darcies] = 8.8900
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	214.6	0.194	0.351	154.80	10.20	524.20	49.55	15.18	34.41	0.048
1.10	1.00	52.9	0.0	0.048	0.071	51.30	2.50	526.70	49.78	20.52	28.40	0.047
1.10	1.00	0.0	211.6	0.191	0.354	150.00	15.00	541.70	51.20	10.00	23.60	0.071
1.10	1.00	0.0	253.4	0.229	0.511	224.00	25.00	566.70	53.56	8.96	20.44	0.099
1.00	1.00	0.0	252.1	0.228	0.503	240.00	9.00	575.70	54.41	26.67	55.89	0.036
0.01	0.01	0.0	0.0	0.000	0.595	176.00	28.00	603.70	57.06	6.29	21.25	

TABLE A21

RESULTS OF RUN 1DT21
[0.40 HCPV CO2-N2 @ 1.0 MPa (0.180 g-mol) 4:1 WAG, 10 Slugs, DEAD OIL]

Porosity [%] = 35.9
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 8.27

Pore Volume [cm3] = 1117.0
Initial Oil Saturation [%] = 94.7
Hydrocarbon Pore Volume [cm3] = 1057.4
Carbon Dioxide Retention [%inj] = 27.31

Connate Water Saturation [%] = 5.3
Molar Density @ atm. [kmol/m3] = 0.04163
Absolute Permeability [darcies] = 11.4500
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	42.3	0.0	0.038	0.000	0.00	16.50	16.50	1.56	0.00	0.00	0.390
1.20	1.00	0.0	169.2	0.151	0.020	0.00	160.50	177.00	16.74	0.00	0.12	0.949
1.20	1.00	42.3	0.0	0.038	0.010	8.90	40.60	217.60	20.58	0.22	0.25	0.960
1.10	1.00	0.0	169.2	0.151	0.035	61.50	63.50	281.10	26.58	0.97	0.55	0.375
1.10	1.00	42.3	0.0	0.038	0.026	31.20	13.80	294.90	27.89	2.26	1.88	0.326
1.10	1.00	0.0	169.2	0.151	0.063	76.00	50.00	344.90	32.62	1.52	1.26	0.296
1.10	1.00	42.3	0.0	0.038	0.024	38.00	10.60	355.50	33.62	3.58	2.26	0.251
1.10	1.00	0.0	169.2	0.151	0.107	90.50	29.50	385.00	36.41	3.07	3.63	0.174
1.10	1.00	42.3	0.0	0.038	0.031	41.00	7.50	392.50	37.12	5.47	4.13	0.177
1.10	1.00	0.0	169.2	0.151	0.159	105.00	17.00	409.50	38.73	6.18	9.35	0.100
1.10	1.00	42.3	0.0	0.038	0.052	40.60	4.90	414.40	39.19	8.29	10.61	0.116
1.10	1.00	0.0	169.2	0.151	0.314	102.80	24.20	438.60	41.48	4.25	12.98	0.143
1.10	1.00	42.3	0.0	0.038	0.038	40.70	4.30	442.90	41.89	9.47	8.84	0.102
1.10	1.00	0.0	169.2	0.151	0.368	100.00	22.50	465.40	44.01	4.44	16.36	0.133
1.10	1.00	42.3	0.0	0.038	0.059	44.80	5.70	471.10	44.55	7.86	10.35	0.135
1.10	1.00	0.0	169.2	0.151	0.398	102.00	20.00	491.10	46.44	5.10	19.90	0.118
1.10	1.00	42.3	0.0	0.038	0.045	15.50	1.50	492.60	46.59	10.33	30.00	0.035

TABLE A21 (CONTINUED)

RESULTS OF RUN 1DT21
[0.40 HCPV CO2-N2 @ 1.0 MPa (0.180 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.9
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 8.27

Pore Volume [cm3] = 1117.0
Initial Oil Saturation [%] = 94.7
Hydrocarbon Pore Volume [cm3] = 1057.4
Carbon Dioxide Retention [%inj] = 27.31

Connate Water Saturation [%] = 5.3
Molar Density @ atm. [kmol/m3] = 0.04163
Absolute Permeability [darcies] = 11.4500
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	169.2	0.151	0.382	132.00	17.00	509.60	48.19	7.76	22.47	0.100
1.10	1.00	42.3	0.0	0.038	0.058	46.00	2.00	511.60	48.38	23.00	29.00	0.047
1.10	1.00	0.0	169.3	0.152	0.362	112.00	11.00	522.60	49.42	10.18	32.91	0.065
1.10	1.00	0.0	249.1	0.223	0.265	237.00	11.00	533.60	50.46	21.55	24.09	0.044
1.10	1.00	0.0	244.6	0.219	0.196	229.00	14.00	547.60	51.79	16.36	14.00	0.057
1.10	1.00	0.0	243.3	0.218	0.205	228.00	15.00	562.60	53.21	15.20	13.67	0.062
1.10	1.00	0.0	246.0	0.220	0.167	238.00	10.00	572.60	54.15	23.80	16.70	0.041
0.01	0.01	0.0	0.0	0.000	0.192	136.00	22.00	594.60	56.23	6.18	8.73	

TABLE A22

RESULTS OF RUN 1DT22

[0.40 HCPV CO2-N2 @ 1.00 MPa (0.178 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.8
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 8.48

Pore Volume [cm3] = 1114.0
Initial Oil Saturation [%] = 94.2
Hydrocarbon Pore Volume [cm3] = 1049.0
Carbon Dioxide Retention [%inj] = 17.58

Connate Water Saturation [%] = 5.8
Molar Density @ atm. [kmol/m3] = 0.04162
Absolute Permeability [darcies] = 11.0500
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	41.9	0.0	0.038	0.001	0.00	3.50	3.50	0.33	0.00	0.29	0.083
1.10	1.00	0.0	167.8	0.151	0.000	2.00	164.00	167.50	15.97	0.01	0.00	0.977
1.20	1.00	41.9	0.0	0.038	0.000	8.00	32.50	200.00	19.07	0.25	0.00	0.775
1.10	1.00	0.0	167.8	0.151	0.000	69.00	68.00	268.00	25.55	1.01	0.00	0.405
1.10	1.00	41.9	0.0	0.038	0.005	31.50	13.50	281.50	26.84	2.33	0.37	0.322
1.10	1.00	0.0	167.8	0.151	0.070	106.00	21.00	302.50	28.84	5.05	3.33	0.125
1.10	1.00	41.9	0.0	0.038	0.017	33.00	11.00	313.50	29.89	3.00	1.55	0.262
1.10	1.00	0.0	167.8	0.151	0.214	107.80	18.20	331.70	31.62	5.92	11.76	0.108
1.10	1.00	41.9	0.0	0.038	0.011	21.00	3.50	335.20	31.95	6.00	3.14	0.083
1.10	1.00	0.0	167.8	0.151	0.172	112.00	31.00	366.20	34.91	3.61	5.55	0.185
1.10	1.00	41.9	0.0	0.038	0.036	39.90	5.60	371.80	35.44	7.12	6.43	0.134
1.10	1.00	0.0	167.8	0.151	0.378	102.50	21.50	393.30	37.49	4.77	17.58	0.128
1.10	1.00	41.9	0.0	0.038	0.039	40.30	5.70	399.00	38.04	7.07	6.84	0.136
1.10	1.00	0.0	167.8	0.151	0.446	98.00	24.00	423.00	40.32	4.08	18.58	0.143
1.10	1.00	41.9	0.0	0.038	0.058	44.00	6.00	429.00	40.90	7.33	9.67	0.143
1.10	1.00	0.0	167.8	0.151	0.516	102.00	18.00	447.00	42.61	5.67	28.67	0.107
1.10	1.00	41.9	0.0	0.038	0.052	47.30	3.30	450.30	42.93	14.33	15.76	0.079

TABLE A22 (CONTINUED)

RESULTS OF RUN 1DT22
[0.40 HCPV CO2-N2 @ 1.00 MPa (0.178 g-mol) 4:1 WAG, 10 Slugs, DEAD OIL]

Porosity [%] = 35.8
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 8.48

Pore Volume [cm3] = 1114.0
Initial Oil Saturation [%] = 94.2
Hydrocarbon Pore Volume [cm3] = 1049.0
Carbon Dioxide Retention [%inj] = 17.58

Connate Water Saturation [%] = 5.8
Molar Density @ atm. [kmol/m3] = 0.04162
Absolute Permeability [darcies] = 11.0500
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	167.8	0.151	0.556	105.00	18.50	468.80	44.69	5.68	30.05	0.110
1.10	1.00	41.9	0.0	0.038	0.057	22.60	1.90	470.70	44.87	11.89	30.00	0.045
1.10	1.00	0.0	167.8	0.151	0.175	120.00	20.00	490.70	46.78	6.00	8.75	0.119
1.10	1.00	0.0	251.8	0.226	0.207	235.00	18.00	508.70	48.49	13.06	11.50	0.071
1.10	1.00	0.0	245.0	0.220	0.185	228.00	15.00	523.70	49.92	15.20	12.33	0.061
1.10	1.00	0.0	249.9	0.224	0.191	234.00	16.00	539.70	51.45	14.63	11.94	0.064
0.01	0.01	0.0	0.0	0.000	0.637	155.00	36.00	575.70	54.88	4.31	17.69	

TABLE A23

RESULTS OF RUN 1DT23

[0.20 HCPV CO2-N2 @ 1.0 MPa (0.090 g-mol) 4:1 WAG, 10 Slugs, DEAD OIL]

Porosity [%] = 35.7
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.24

Pore Volume [cm3] = 1111.0
Initial Oil Saturation [%] = 94.9
Hydrocarbon Pore Volume [cm3] = 1054.6
Carbon Dioxide Retention [%inj] = 38.35

Connate Water Saturation [%] = 5.1
Molar Density @ atm. [kmol/m3] = 0.04135
Absolute Permeability [darcies] = 11.2200
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	DPFIR -- (sm3/m3)
1.10	1.00	21.1	0.0	0.019	0.000	0.00	6.50	6.50	0.62	0.00	0.00	0.307
1.20	1.00	0.0	84.4	0.076	0.000	0.00	83.50	90.00	8.53	0.00	0.00	0.990
1.20	1.00	21.1	0.0	0.019	0.000	0.00	20.60	110.60	10.49	0.00	0.00	0.974
1.10	1.00	0.0	84.4	0.076	0.000	0.00	69.50	180.10	17.08	0.00	0.00	0.824
1.10	1.00	21.1	0.0	0.019	0.000	9.00	31.00	211.10	20.02	0.29	0.00	1.466
1.10	1.00	0.0	84.4	0.076	0.009	22.00	27.50	238.60	22.62	0.80	0.33	0.326
1.10	1.00	21.1	0.0	0.019	0.003	18.00	13.50	252.10	23.90	1.33	0.22	0.639
1.10	1.00	0.0	84.4	0.076	0.015	27.00	27.50	279.60	26.51	0.98	0.55	0.326
1.10	1.00	21.1	0.0	0.019	0.013	18.00	6.50	286.10	27.13	2.77	2.00	0.307
1.10	1.00	0.0	84.4	0.076	0.030	38.30	23.70	309.80	29.38	1.62	1.27	0.281
1.10	1.00	21.1	0.0	0.019	0.021	27.80	7.10	316.90	30.05	3.92	2.96	0.336
1.10	1.00	0.0	84.4	0.076	0.093	37.20	15.30	332.20	31.50	2.43	6.08	0.181
1.10	1.00	21.1	0.0	0.019	0.025	26.70	4.30	336.50	31.91	6.21	5.81	0.203
1.10	1.00	0.0	84.4	0.076	0.083	43.50	12.00	348.50	33.05	3.63	6.92	0.142
1.10	1.00	21.1	0.0	0.019	0.028	28.00	3.50	352.00	33.38	8.00	8.00	0.166
1.10	1.00	0.0	84.4	0.076	0.125	47.50	9.50	361.50	34.28	5.00	13.16	0.113
1.10	1.00	21.1	0.0	0.019	0.025	28.50	3.50	365.00	34.61	8.14	7.14	0.166

TABLE A23 (CONTINUED)

RESULTS OF RUN 1DT23
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.090 g-mol) 4:1 WAG, 10 Slugs, DEAD OIL]

Porosity [%] = 35.7
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.24

Pore Volume [cm3] = 1111.0
Initial Oil Saturation [%] = 94.9
Hydrocarbon Pore Volume [cm3] = 1054.6
Carbon Dioxide Retention [%inj] = 38.35

Connate Water Saturation [%] = 5.1
Molar Density @ atm. [kmol/m3] = 0.04135
Absolute Permeability [darcies] = 11.2200
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	84.4	0.076	0.157	46.00	10.00	375.00	35.56	4.60	15.70	0.118
1.10	1.00	21.1	0.0	0.019	0.027	21.50	3.00	378.00	35.84	7.17	9.00	0.142
1.10	1.00	0.0	84.4	0.076	0.175	48.00	15.00	393.00	37.27	3.20	11.67	0.178
1.10	1.00	0.0	254.0	0.229	0.154	190.00	64.00	457.00	43.33	2.97	2.41	0.252
1.10	1.00	0.0	255.7	0.230	0.158	223.00	32.00	489.00	46.37	6.97	4.94	0.125
1.10	1.00	0.0	250.6	0.226	0.201	230.00	20.00	509.00	48.26	11.50	10.05	0.080
1.10	1.00	0.0	250.3	0.225	0.219	230.00	30.00	539.00	51.11	7.67	7.30	0.120
1.10	1.10	0.0	245.3	0.221	0.132	234.00	11.00	550.00	52.15	21.27	12.00	0.045
0.01	0.01	0.0	0.0	0.000	0.255	100.00	23.70	573.70	54.38	2.94	7.50	

TABLE A24

RESULTS OF RUN 1DT24
[0.40 HCPV CO2-N2 @ 1.0 MPa (0.180 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.6
Oil Viscosity [mPa.s] = 886.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 8.41

Pore Volume [cm3] = 1106.5
Initial Oil Saturation [%] = 94.9
Hydrocarbon Pore Volume [cm3] = 1050.0
Carbon Dioxide Retention [%inj] = 35.35

Connate Water Saturation [%] = 5.1
Molar Density @ atm. [kmol/m3] = 0.04162
Absolute Permeability [darcies] = 10.9000
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	42.0	0.0	0.038	0.000	0.00	5.00	5.00	0.48	0.00	0.00	0.119
1.30	1.00	0.0	168.0	0.152	0.000	0.00	157.40	162.40	15.47	0.00	0.00	0.937
1.20	1.00	42.0	0.0	0.038	0.000	0.00	32.55	194.95	18.57	0.00	0.00	0.775
1.10	1.00	0.0	168.0	0.152	0.000	31.00	73.30	268.25	25.55	0.42	0.00	0.436
1.10	1.00	42.0	0.0	0.038	0.000	22.00	13.55	281.80	26.84	1.62	0.00	0.323
1.10	1.00	0.0	168.0	0.152	0.362	60.50	21.53	303.33	28.89	2.81	16.81	0.128
1.10	1.00	42.0	0.0	0.038	0.000	21.00	11.03	314.36	29.94	1.90	0.00	0.263
1.10	1.00	0.0	168.0	0.152	0.137	74.00	19.30	333.66	31.78	3.83	7.10	0.115
1.10	1.00	42.0	0.0	0.038	0.007	30.00	3.50	337.16	32.11	8.57	2.00	0.083
1.10	1.00	0.0	168.0	0.152	0.179	73.50	30.00	367.16	34.97	2.45	5.97	0.179
1.10	1.00	42.0	0.0	0.038	0.005	15.50	5.60	372.76	35.50	2.77	0.89	0.133
1.10	1.00	0.0	168.0	0.152	0.091	95.50	21.00	393.76	37.50	4.55	4.33	0.125
1.10	1.00	42.0	0.0	0.038	0.010	22.00	5.70	399.46	38.04	3.86	1.75	0.136
1.10	1.00	0.0	168.0	0.152	0.072	90.50	24.00	423.46	40.33	3.77	3.00	0.143
1.10	1.00	42.0	0.0	0.038	0.016	29.00	6.00	429.46	40.90	4.83	2.67	0.143
1.10	1.00	0.0	168.0	0.152	0.208	80.00	18.00	447.46	42.62	4.44	11.56	0.107
1.10	1.00	42.0	0.0	0.038	0.011	25.70	3.25	450.71	42.92	7.91	3.38	0.077

TABLE A24 (CONTINUED)

RESULTS OF RUN 1DT24
[0.40 HCPV CO2-N2 @ 1.0 MPa (0.180 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.6
Oil Viscosity [mPa.s] = 886.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 8.41

Pore Volume [cm3] = 1106.5
Initial Oil Saturation [%] = 94.9
Hydrocarbon Pore Volume [cm3] = 1050.0
Carbon Dioxide Retention [%inj] = 35.35

Connate Water Saturation [%] = 5.1
Molar Density @ atm. [kmol/m3] = 0.04162
Absolute Permeability [darcies] = 10.9000
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	168.0	0.152	0.198	83.00	18.30	469.01	44.67	4.54	10.82	0.109
1.10	1.00	42.0	0.0	0.038	0.016	21.80	1.90	470.91	44.85	11.47	8.42	0.045
1.10	1.00	0.0	168.0	0.152	0.240	83.00	20.30	491.21	46.78	4.09	11.82	0.121
1.10	1.00	0.0	250.7	0.227	0.173	231.00	18.00	509.21	48.50	12.83	9.61	0.072
1.10	1.00	0.0	246.4	0.223	0.211	223.00	21.20	530.41	50.52	10.52	9.95	0.086
1.10	1.00	0.0	250.9	0.227	0.204	234.00	14.00	544.41	51.85	16.71	14.57	0.056
0.01	0.01	0.0	0.0	0.000	0.374	117.00	27.40	571.81	54.46	4.27	13.65	

TABLE A25

RESULTS OF RUN 1DT25

[0.20 HCPV CO2-N2 @ 1.0 MPa (0.091 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.4
Oil Viscosity [mPa.s] = 1055.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.84

Pore Volume [cm3] = 1102.0
Initial Oil Saturation [%] = 96.0
Hydrocarbon Pore Volume [cm3] = 1058.0
Carbon Dioxide Retention [%inj] = 37.53

Connate Water Saturation [%] = 4.0
Molar Density @ atm. [kmol/m3] = 0.04133
Absolute Permeability [darcies] = 9.4400
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	21.1	0.0	0.019	0.000	0.00	10.00	10.00	0.95	0.00	0.00	0.473
1.20	1.00	0.0	84.9	0.077	0.000	0.00	77.70	87.70	8.29	0.00	0.00	0.915
1.10	1.00	21.1	0.0	0.019	0.000	0.00	33.50	121.20	11.46	0.00	0.00	1.585
1.20	1.00	0.0	84.6	0.077	0.000	0.00	61.00	182.20	17.22	0.00	0.00	0.721
1.10	1.00	21.1	0.0	0.019	0.001	7.80	28.90	211.10	19.95	0.27	0.03	1.367
1.20	1.00	0.0	84.6	0.077	0.009	21.50	29.50	240.60	22.74	0.73	0.31	0.349
1.20	1.00	21.1	0.0	0.019	0.001	8.00	6.20	246.80	23.33	1.29	0.16	0.293
1.10	1.00	0.0	84.6	0.077	0.022	46.50	26.00	272.80	25.78	1.79	0.85	0.307
1.10	1.00	21.1	0.0	0.019	0.010	31.00	7.10	279.90	26.46	4.37	1.41	0.336
1.10	1.00	0.0	88.3	0.080	0.025	40.30	13.20	293.10	27.70	3.05	1.89	0.149
1.10	1.00	21.1	0.0	0.019	0.005	32.10	6.60	299.70	28.33	4.86	0.76	0.312
1.10	1.00	0.0	84.6	0.077	0.013	39.00	13.00	312.70	29.56	3.00	1.00	0.154
1.10	1.00	21.1	0.0	0.019	0.005	32.80	3.80	316.50	29.91	8.63	1.32	0.180
1.00	1.00	0.0	84.6	0.077	0.052	38.00	11.50	328.00	31.00	3.30	4.52	0.136
1.10	1.00	21.1	0.0	0.019	0.014	34.00	4.50	332.50	31.43	7.56	3.11	0.213
1.10	1.00	0.0	84.6	0.077	0.051	39.00	16.00	348.50	32.94	2.44	3.19	0.189
1.10	1.00	21.1	0.0	0.019	0.034	33.00	4.40	352.90	33.36	7.50	7.73	0.208

TABLE A25 (CONTINUED)

RESULTS OF RUN 1DT25
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.091 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.4
Oil Viscosity [mPa.s] = 1055.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.84
Pore Volume [cm3] = 1102.0
Initial Oil Saturation [%] = 96.0
Hydrocarbon Pore Volume [cm3] = 1058.0
Carbon Dioxide Retention [%inj] = 37.53
Connate Water Saturation [%] = 4.0
Molar Density @ atm. [kmol/m3] = 0.04133
Absolute Permeability [darcies] = 9.4400
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	84.6	0.077	0.113	38.00	14.00	366.90	34.68	2.71	8.07	0.165
1.10	1.00	21.1	0.0	0.019	0.031	34.60	3.50	370.40	35.01	9.89	8.86	0.166
1.10	1.00	0.0	84.6	0.077	0.114	34.00	14.00	384.40	36.33	2.43	8.14	0.165
1.10	1.00	0.0	256.0	0.232	0.380	212.50	34.50	418.90	39.59	6.16	11.01	0.135
1.10	1.00	0.0	252.7	0.229	0.265	214.00	37.00	455.90	43.09	5.78	7.16	0.146
1.10	1.00	0.0	253.7	0.230	0.155	229.00	18.00	473.90	44.79	12.72	8.61	0.071
1.10	1.00	0.0	249.3	0.226	0.058	241.50	7.50	481.40	45.50	32.20	7.73	0.030
0.01	0.01	0.0	0.0	0.000	0.190	140.00	30.50	511.90	48.38	4.59	6.23	

TABLE A26

RESULTS OF RUN 1DT26
[0.30 HCPV CO2-N2 @ 1.0 MPa (0.142 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 37.6
Oil Viscosity [mPa.s] = 1055.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 6.48

Pore Volume [cm3] = 1168.0
Initial Oil Saturation [%] = 94.8
Hydrocarbon Pore Volume [cm3] = 1106.9
Carbon Dioxide Retention [%inj] = 57.72

Connate Water Saturation [%] = 5.2
Molar Density @ atm. [kmol/m3] = 0.04133
Absolute Permeability [darcies] = 11.3500
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.20	1.00	33.2	0.0	0.028	0.002	0.50	11.70	11.70	1.06	0.04	0.17	0.352
1.20	1.00	0.0	132.7	0.114	0.004	0.00	126.00	137.70	12.44	0.00	0.03	0.949
1.10	1.00	33.2	0.0	0.028	0.000	3.00	33.00	170.70	15.42	0.09	0.00	0.994
1.20	1.00	0.0	132.8	0.114	0.005	35.80	65.20	235.90	21.31	0.55	0.08	0.491
1.10	1.00	33.2	0.0	0.028	0.001	27.80	16.70	252.60	22.82	1.66	0.06	0.503
1.10	1.00	0.0	132.8	0.114	0.010	63.00	29.00	281.60	25.44	2.17	0.34	0.218
1.10	1.00	33.2	0.0	0.028	0.005	34.50	11.00	292.60	26.43	3.14	0.45	0.331
1.10	1.00	0.0	132.8	0.114	0.014	70.00	24.00	316.60	28.60	2.92	0.58	0.181
1.10	1.00	33.2	0.0	0.028	0.014	34.80	12.70	329.30	29.75	2.74	1.10	0.382
1.10	1.00	0.0	132.7	0.114	0.026	69.00	19.00	348.30	31.47	3.63	1.37	0.143
1.10	1.00	33.2	0.0	0.028	0.027	37.70	7.30	355.60	32.13	5.16	3.70	0.220
1.10	1.00	0.0	132.7	0.114	0.020	76.00	18.00	373.60	33.75	4.22	1.11	0.136
1.10	1.00	33.2	0.0	0.028	0.025	37.00	5.00	378.60	34.20	7.40	5.00	0.151
1.00	1.00	0.0	132.7	0.114	0.051	69.00	20.00	398.60	36.01	3.45	2.55	0.151
1.10	1.00	33.2	0.0	0.028	0.014	42.00	5.00	403.60	36.46	8.40	2.80	0.151
1.10	1.00	0.0	132.7	0.114	0.055	76.00	15.00	418.60	37.82	5.07	3.67	0.113
1.10	1.00	33.2	0.0	0.028	0.036	34.50	4.00	422.60	38.18	8.63	9.00	0.120

TABLE A26 (CONTINUED)

RESULTS OF RUN 1DT26
[0.30 HCPV CO2-N2 @ 1.0 MPa (0.142 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 37.6
Oil Viscosity [mPa.s] = 1055.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 6.48

Pore Volume [cm3] = 1168.0
Initial Oil Saturation [%] = 94.8
Hydrocarbon Pore Volume [cm3] = 1106.9
Carbon Dioxide Retention [%inj] = 57.72

Connate Water Saturation [%] = 5.2
Molar Density @ atm. [kmol/m3] = 0.04133
Absolute Permeability [darcies] = 11.3500
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	132.7	0.114	0.114	79.00	19.00	441.60	39.90	4.16	6.00	0.143
1.10	1.00	33.2	0.0	0.028	0.038	35.50	4.50	446.10	40.30	7.89	8.44	0.136
1.10	1.00	0.0	132.8	0.114	0.115	68.00	19.00	465.10	42.02	3.58	6.05	0.143
1.10	1.00	0.0	258.4	0.221	0.382	234.00	19.00	484.10	43.73	12.32	20.11	0.074
1.10	1.00	0.0	254.8	0.218	0.274	235.00	14.00	498.10	45.00	16.79	19.57	0.055
1.10	1.00	0.0	249.2	0.213	0.153	242.00	8.00	506.10	45.72	30.25	19.12	0.032
0.01	0.01	0.0	0.0	0.000	0.261	119.00	95.00	601.10	54.30	1.25	2.75	

TABLE A27

RESULTS OF RUN 1DT27
[0.21 HCPV CO2-N2 @ 1.0 MPa (0.099 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 36.1
Oil Viscosity [mPa.s] = 1055.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.19

Pore Volume [cm3] = 1121.0
Initial Oil Saturation [%] = 97.7
Hydrocarbon Pore Volume [cm3] = 1095.0
Carbon Dioxide Retention [%inj] = 34.47

Connate Water Saturation [%] = 2.3
Molar Density @ atm. [kmol/m3] = 0.04136
Absolute Permeability [darcies] = 9.8010
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	23.1	0.0	0.021	0.000	0.00	3.00	3.00	0.27	0.00	0.00	0.130
1.40	1.00	0.0	92.4	0.082	0.001	0.00	90.50	93.50	8.54	0.00	0.01	0.979
1.40	1.00	23.1	0.0	0.021	0.001	0.00	29.00	122.50	11.19	0.00	0.03	1.257
1.10	1.00	0.0	92.4	0.082	0.001	0.00	70.20	192.70	17.60	0.00	0.01	0.759
1.10	1.00	23.1	0.0	0.021	0.001	5.00	23.00	215.70	19.70	0.22	0.04	0.997
1.10	1.00	0.0	92:4	0.082	0.009	15.20	38.40	254.10	23.21	0.40	0.23	0.415
1.10	1.00	23.1	0.0	0.021	0.003	18.90	14.60	268.70	24.54	1.29	0.21	0.633
1.10	1.00	0.0	92.4	0.082	0.022	40.30	22.20	290.90	26.57	1.82	0.99	0.240
1.10	1.00	23.1	0.0	0.021	0.011	24.60	7.40	298.30	27.24	3.32	1.49	0.321
1.10	1.00	0.0	92.4	0.082	0.025	43.00	20.00	318.30	29.07	2.15	1.25	0.216
1.10	1.00	23.1	0.0	0.021	0.006	32.10	6.40	324.70	29.65	5.02	0.94	0.277
1.10	1.00	0.0	92.5	0.082	0.024	42.00	16.00	340.70	31.11	2.63	1.50	0.173
1.10	1.00	23.1	0.0	0.021	0.029	29.20	4.30	345.00	31.51	6.79	6.74	0.186
1.10	1.00	0.0	92.4	0.082	0.052	50.50	11.50	356.50	32.56	4.39	4.52	0.124
1.10	1.00	23.1	0.0	0.021	0.020	31.40	2.40	358.90	32.78	13.08	8.33	0.104
1.10	1.00	0.0	92.5	0.082	0.054	54.50	9.50	368.40	33.64	5.74	5.68	0.103
1.10	1.00	23.1	0.0	0.021	0.026	30.30	2.90	371.30	33.91	10.45	8.97	0.126

TABLE A27 (CONTINUED)

RESULTS OF RUN 1DT27
[0.21 HCPV CO2-N2 @ 1.0 MPa (0.099 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 36.1
Oil Viscosity [mPa.s] = 1055.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.19

Pore Volume [cm3] = 1121.0
Initial Oil Saturation [%] = 97.7
Hydrocarbon Pore Volume [cm3] = 1095.0
Carbon Dioxide Retention [%inj] = 34.47

Connate Water Saturation [%] = 2.3
Molar Density @ atm. [kmol/m3] = 0.04136
Absolute Permeability [darcies] = 9.8010
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	92.4	0.082	0.133	44.00	18.00	389.30	35.55	2.44	7.39	0.195
1.10	1.00	23.1	0.0	0.021	0.053	32.00	4.20	393.50	35.94	7.62	12.62	0.182
1.10	1.00	0.0	92.4	0.082	0.114	42.00	20.30	413.80	37.79	2.07	5.62	0.220
1.10	1.00	0.0	257.1	0.229	0.382	210.00	35.00	448.80	40.99	6.00	10.91	0.136
1.20	1.00	0.0	244.7	0.218	0.180	227.50	16.50	465.30	42.49	13.79	10.91	0.067
1.10	1.10	0.0	233.3	0.208	0.210	222.00	22.00	487.30	44.50	10.09	9.55	0.094
0.01	0.01	0.0	0.0	0.000	0.449	130.00	44.00	531.30	48.52	2.95	10.20	

TABLE A28

RESULTS OF RUN 1DT28
[0.40 HCPV CO2-N2 @ 1.00 MPa (0.181 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.8
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 7.89

Pore Volume [cm3] = 1112.0
Initial Oil Saturation [%] = 95.3
Hydrocarbon Pore Volume [cm3] = 1060.0
Carbon Dioxide Retention [%inj] = 42.60

Connate Water Saturation [%] = 4.7
Molar Density @ atm. [kmol/m3] = 0.04163
Absolute Permeability [darcies] = 11.1200
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.30	1.00	42.4	0.0	0.038	0.000	0.00	14.60	14.60	1.38	0.00	0.00	0.345
1.30	1.00	0.0	169.6	0.153	0.000	0.00	155.80	170.40	16.08	0.00	0.00	0.919
1.10	1.00	42.4	0.0	0.038	0.001	7.00	43.00	213.40	20.13	0.16	0.02	1.015
1.10	1.00	0.0	169.6	0.153	0.003	53.00	73.00	286.40	27.02	0.73	0.04	0.430
1.10	1.00	42.4	0.0	0.038	0.006	32.00	15.00	301.40	28.43	2.13	0.40	0.354
1.10	1.00	0.0	169.6	0.153	0.022	94.50	28.50	329.90	31.12	3.32	0.77	0.168
1.10	1.00	42.4	0.0	0.038	0.010	37.80	7.50	337.40	31.83	5.04	1.33	0.177
1.10	1.00	0.0	169.7	0.153	0.047	99.00	29.00	366.40	34.57	3.41	1.62	0.171
1.10	1.00	42.4	0.0	0.038	0.028	35.50	14.00	380.40	35.89	2.54	2.00	0.330
1.10	1.00	0.0	169.6	0.153	0.046	95.00	29.00	409.40	38.62	3.28	1.59	0.171
1.10	1.00	42.4	0.0	0.038	0.049	45.50	5.50	414.90	39.14	8.27	8.91	0.130
1.10	1.00	0.0	169.6	0.153	0.052	100.00	18.50	433.40	40.89	5.41	2.81	0.109
1.10	1.00	42.4	0.0	0.038	0.030	22.50	3.00	436.40	41.17	7.50	10.00	0.071
1.10	1.00	0.0	171.9	0.155	0.158	128.00	23.00	459.40	43.34	5.57	6.87	0.134
1.10	1.00	42.4	0.0	0.038	0.049	39.40	4.10	463.50	43.73	9.61	11.95	0.097
1.10	1.00	0.0	169.6	0.153	0.125	106.00	23.00	486.50	45.90	4.61	5.43	0.136
1.10	1.00	42.4	0.0	0.038	0.038	39.00	3.00	489.50	46.18	13.00	12.67	0.071

TABLE A28 (CONTINUED)

RESULTS OF RUN 1DT28

[0.40 HCPV CO2-N2 @ 1.00 MPa (0.181 g-mol) 4:1 WAG,10 Slugs, DEAD OIL] 1c

Porosity [%] = 35.8
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 7.89

Pore Volume [cm3] = 1112.0
Initial Oil Saturation [%] = 95.3
Hydrocarbon Pore Volume [cm3] = 1060.0
Carbon Dioxide Retention [%inj] = 42.60

Connate Water Saturation [%] = 4.7
Molar Density @ atm. [kmol/m3] = 0.04163
Absolute Permeability [darcies] = 11.1200
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	169.6	0.153	0.279	112.00	21.00	510.50	48.16	5.33	13.29	0.124
1.10	1.00	42.4	0.0	0.038	0.076	40.00	2.00	512.50	48.35	20.00	38.00	0.047
1.10	1.00	0.0	169.6	0.153	0.326	111.00	19.50	532.00	50.19	5.69	16.72	0.115
1.10	1.00	0.0	250.2	0.225	0.263	223.80	23.20	555.20	52.38	9.65	11.34	0.093
1.10	1.00	0.0	247.4	0.222	0.305	223.80	19.20	574.40	54.19	11.66	15.89	0.078
1.10	1.00	0.0	243.8	0.219	0.337	229.00	14.00	588.40	55.51	16.36	24.07	0.057
1.10	1.00	0.0	247.0	0.222	0.236	240.00	7.00	595.40	56.17	34.29	33.71	0.028
0.01	0.01	0.0	0.0	0.000	0.372	135.00	36.00	631.40	59.57	3.75	10.33	

TABLE A29

RESULTS OF RUN 1DT29
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.092 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.8
Oil Viscosity [mPa.s] = 868.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.21

Pore Volume [cm3] = 1133.0
Initial Oil Saturation [%] = 94.5
Hydrocarbon Pore Volume [cm3] = 1075.8
Carbon Dioxide Retention [%inj] = 29.35

Connate Water Saturation [%] = 5.5
Molar Density @ atm. [kmol/m3] = 0.04136
Absolute Permeability [darcies] = 10.6100
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	21.4	0.0	0.019	0.000	0.00	3.50	3.50	0.33	0.00	0.00	0.163
1.20	1.00	0.0	86.1	0.076	0.001	0.00	83.80	87.30	8.11	0.00	0.01	0.973
1.20	1.00	21.4	0.0	0.019	0.001	0.00	17.00	104.30	9.70	0.00	0.06	0.793
1.10	1.00	0.0	86.5	0.076	0.000	0.00	74.50	178.80	16.62	0.00	0.00	0.861
1.10	1.00	21.4	0.0	0.019	0.000	3.00	33.50	212.30	19.73	0.09	0.00	1.562
1.10	1.00	0.0	86.1	0.076	0.004	14.20	38.30	250.60	23.29	0.37	0.10	0.445
1.10	1.00	21.4	0.0	0.019	0.011	17.50	17.00	267.60	24.87	1.03	0.65	0.793
1.10	1.00	0.0	86.1	0.076	0.017	32.70	21.80	289.40	26.90	1.50	0.78	0.253
1.10	1.00	21.4	0.0	0.019	0.011	22.50	6.50	295.90	27.51	3.46	1.69	0.303
1.10	1.00	0.0	86.1	0.076	0.011	42.40	16.10	312.00	29.00	2.63	0.68	0.187
1.10	1.00	21.4	0.0	0.019	0.011	26.00	4.00	316.00	29.37	6.50	2.75	0.186
1.10	1.00	0.0	86.1	0.076	0.041	46.50	14.00	330.00	30.67	3.32	2.93	0.163
1.10	1.00	21.4	0.0	0.019	0.016	30.00	3.00	333.00	30.95	10.00	5.33	0.140
1.10	1.00	0.0	86.1	0.076	0.046	45.00	11.00	344.00	31.98	4.09	4.18	0.128
1.10	1.00	21.4	0.0	0.019	0.030	30.50	3.00	347.00	32.26	10.17	10.00	0.140
1.10	1.00	0.0	86.1	0.076	0.070	46.60	9.40	356.40	33.13	4.96	7.45	0.109
1.10	1.00	21.4	0.0	0.019	0.038	28.70	3.80	360.20	33.48	7.55	10.00	0.177

TABLE A29 (CONTINUED)

RESULTS OF RUN 1DT29
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.092 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.8
Oil Viscosity [mPa.s] = 888.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.21

Pore Volume [cm3] = 1133.0
Initial Oil Saturation [%] = 94.5
Hydrocarbon Pore Volume [cm3] = 1075.8
Carbon Dioxide Retention [%inj] = 29.35

Connate Water Saturation [%] = 5.5
Molar Density @ atm. [kmol/m3] = 0.04136
Absolute Permeability [darcies] = 10.6100
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	86.1	0.076	0.114	44.00	14.00	374.20	34.78	3.14	8.14	0.163
1.10	1.00	21.4	0.0	0.019	0.044	27.30	3.70	377.90	35.13	7.38	11.89	0.172
1.10	1.00	0.0	100.4	0.089	0.120	55.00	18.00	395.90	36.80	3.06	6.67	0.179
1.10	1.00	0.0	240.7	0.212	0.286	164.00	73.00	468.90	43.59	2.25	3.92	0.303
1.10	1.00	0.0	242.4	0.214	0.317	203.00	36.00	504.90	46.93	5.64	8.81	0.148
1.10	1.00	0.0	246.2	0.217	0.179	222.00	24.00	528.90	49.16	9.25	7.46	0.097
1.10	1.00	0.0	243.5	0.215	0.141	216.00	26.00	554.90	51.58	8.31	5.42	0.107
1.10	1.00	0.0	243.9	0.215	0.106	230.50	12.50	567.40	52.74	18.44	8.48	0.051
0.01	0.01	0.0	0.0	0.000	0.160	82.00	69.50	636.90	59.20	2.73	5.33	

TABLE A30

RESULTS OF RUN 1DT30
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.082 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 32.2
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 7.12

Pore Volume [cm3] = 1002.0
Initial Oil Saturation [%] = 94.3
Hydrocarbon Pore Volume [cm3] = 944.8
Carbon Dioxide Retention [%inj] = 49.23

Connate Water Saturation [%] = 5.7
Molar Density @ atm. [kmol/m3] = 0.04165
Absolute Permeability [darcies] = 11.8200
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	18.8	0.0	0.019	0.000	0.00	2.00	2.00	0.21	0.00	0.00	0.106
1.40	1.00	0.0	75.6	0.075	0.002	3.20	42.20	44.20	4.68	0.08	0.05	0.558
1.30	1.00	18.8	0.0	0.019	0.000	0.00	7.00	51.20	5.42	0.00	0.00	0.372
1.20	1.00	0.0	75.6	0.075	0.000	12.00	37.20	88.40	9.36	0.32	0.00	0.492
1.20	1.00	18.8	0.0	0.019	0.001	0.00	9.55	97.95	10.37	0.00	0.10	0.507
1.20	1.00	0.0	75.6	0.075	0.009	24.20	25.40	123.35	13.06	0.95	0.35	0.336
1.20	1.00	18.8	0.0	0.019	0.001	11.20	2.65	126.00	13.34	4.23	0.38	0.141
1.10	1.00	0.0	75.6	0.075	0.022	34.00	16.00	142.00	15.03	2.13	1.37	0.212
1.10	1.00	18.8	0.0	0.019	0.010	12.00	1.70	143.70	15.21	7.06	5.88	0.090
1.10	1.00	0.0	75.6	0.075	0.015	45.50	9.00	152.70	16.16	5.06	1.67	0.119
1.10	1.00	18.8	0.0	0.019	0.005	14.10	1.50	154.20	16.32	9.40	3.33	0.080
1.10	1.00	0.0	75.6	0.075	0.013	49.60	5.90	160.10	16.95	8.41	2.20	0.078
1.10	1.00	18.8	0.0	0.019	0.005	13.00	3.30	163.40	17.29	3.94	1.52	0.175
1.10	1.00	0.0	75.6	0.075	0.052	56.50	5.00	168.40	17.82	11.30	10.40	0.066
1.10	1.00	18.8	0.0	0.019	0.023	12.20	2.40	170.80	18.08	5.08	9.58	0.128
1.10	1.00	0.0	75.3	0.075	0.053	56.00	14.00	184.80	19.56	4.00	3.79	0.186
1.10	1.00	18.8	0.0	0.019	0.030	15.30	1.60	186.40	19.73	9.56	18.75	0.085

TABLE A30 (CONTINUED)

RESULTS OF RUN 1DT30

[0.20 HCPV CO2-N2 @ 1.0 MPa (0.082 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 32.2
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 7.12

Pore Volume [cm3] = 1002.0
Initial Oil Saturation [%] = 94.3
Hydrocarbon Pore Volume [cm3] = 944.8
Carbon Dioxide Retention [%inj] = 49.23

Connate Water Saturation [%] = 5.7
Molar Density @ atm. [kmol/m3] = 0.04165
Absolute Permeability [darcies] = 11.8200
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	76.1	0.076	0.113	49.00	4.50	190.90	20.21	10.89	25.11	0.059
1.10	1.00	18.8	0.0	0.019	0.031	15.50	2.20	193.10	20.44	7.05	14.09	0.117
1.10	1.00	0.0	77.2	0.077	0.114	43.50	8.10	201.20	21.30	5.37	14.07	0.105
1.10	1.00	0.0	250.2	0.250	0.125	215.00	35.00	236.20	25.00	6.14	3.57	0.140
1.10	1.00	0.0	252.4	0.252	0.109	223.00	31.50	267.70	28.33	7.08	3.46	0.125
1.10	1.00	0.0	249.1	0.249	0.089	230.00	19.10	286.80	30.36	12.04	4.66	0.077
1.10	1.00	0.0	248.8	0.248	0.084	234.20	16.10	302.90	32.06	14.55	5.22	0.065
1.10	1.00	0.0	241.0	0.241	0.100	235.00	3.20	306.10	32.40	73.44	31.25	0.013
0.01	0.01	0.0	0.0	0.000	0.138	40.20	10.40	316.50	33.50	3.87	13.27	

TABLE A31

RESULTS OF RUN 1DT31
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.094 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 37.1
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.31

Pore Volume [cm3] = 1151.9
Initial Oil Saturation [%] = 95.0
Hydrocarbon Pore Volume [cm3] = 1094.1
Carbon Dioxide Retention [%inj] = 23.98

Connate Water Saturation [%] = 5.0
Molar Density @ atm. [kmol/m3] = 0.04162
Absolute Permeability [darcies] = 11.0500
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	21.9	0.0	0.019	0.000	0.00	6.50	6.50	0.59	0.00	0.00	0.297
1.40	1.00	0.0	87.5	0.076	0.002	0.50	82.40	88.90	8.13	0.01	0.02	0.941
1.10	1.00	21.9	0.0	0.019	0.004	0.00	3.00	91.90	8.40	0.00	1.33	0.137
1.10	1.00	0.0	88.5	0.077	0.003	3.50	81.00	172.90	15.80	0.04	0.04	0.915
1.10	1.00	21.9	0.0	0.019	0.004	8.10	9.00	181.90	16.63	0.90	0.44	0.412
1.10	1.00	0.0	87.6	0.076	0.003	26.50	56.00	237.90	21.74	0.47	0.05	0.640
1.00	1.00	21.9	0.0	0.019	0.010	12.00	8.00	245.90	22.48	1.50	1.25	0.366
1.10	1.00	0.0	87.5	0.076	0.027	34.50	42.10	288.00	26.32	0.82	0.64	0.481
1.10	1.00	21.9	0.0	0.019	0.013	19.00	5.00	293.00	26.78	3.80	2.60	0.229
1.10	1.00	0.0	86.9	0.075	0.017	49.00	28.00	321.00	29.34	1.75	0.61	0.322
1.10	1.00	21.9	0.0	0.019	0.007	20.00	5.00	326.00	29.80	4.00	1.40	0.229
1.10	1.00	0.0	85.0	0.074	0.062	52.50	15.00	341.00	31.17	3.50	4.13	0.176
1.10	1.00	21.9	0.0	0.019	0.018	30.50	3.50	344.50	31.49	8.71	5.14	0.160
1.10	1.00	0.0	87.5	0.076	0.058	52.70	13.90	358.40	32.76	3.79	4.17	0.159
1.10	1.00	21.9	0.0	0.019	0.037	17.50	1.50	359.90	32.89	11.67	24.67	0.069
1.10	1.00	0.0	87.5	0.076	0.060	54.00	12.50	372.40	34.04	4.32	4.80	0.143
1.10	1.00	21.9	0.0	0.019	0.053	5.50	2.00	374.40	34.22	2.75	26.50	0.091

TABLE A31 (CONTINUED)

RESULTS OF RUN 1DT31
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.094 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 37.1
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.31

Pore Volume [cm3] = 1151.9
Initial Oil Saturation [%] = 95.0
Hydrocarbon Pore Volume [cm3] = 1094.1
Carbon Dioxide Retention [%inj] = 23.98

Connate Water Saturation [%] = 5.0
Molar Density @ atm. [kmol/m3] = 0.04162
Absolute Permeability [darcies] = 11.0500
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	87.5	0.076	0.107	68.50	11.70	386.10	35.29	5.85	9.15	0.134
1.10	1.00	21.9	0.0	0.019	0.036	21.00	1.50	387.60	35.43	14.00	24.00	0.069
1.10	1.00	0.0	87.5	0.076	0.088	56.50	15.00	402.60	36.80	3.77	5.87	0.171
1.10	1.00	0.0	252.3	0.219	0.400	203.00	40.00	442.60	40.45	5.07	10.00	0.159
1.10	1.00	0.0	251.5	0.218	0.289	220.50	28.30	470.90	43.04	7.79	10.21	0.113
1.10	1.00	0.0	250.4	0.217	0.166	227.00	22.90	493.80	45.13	9.91	7.25	0.091
1.10	1.00	0.0	257.4	0.223	0.058	244.00	18.00	511.80	46.78	13.56	3.22	0.070
1.10	1.00	0.0	254.1	0.221	0.048	239.00	11.00	522.80	47.78	21.73	4.36	0.043
1.10	1.00	0.0	254.3	0.221	0.047	240.00	10.00	532.80	48.70	24.00	4.70	0.039
0.01	0.01	0.0	0.0	0.000	0.281	212.50	46.00	578.80	52.90	4.62	6.11	

TABLE A32

RESULTS OF RUN 1DT32
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.090 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.6
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 6.42

Pore Volume [cm3] = 1108.0
Initial Oil Saturation [%] = 95.2
Hydrocarbon Pore Volume [cm3] = 1055.0
Carbon Dioxide Retention [%inj] = 14.44

Connate Water Saturation [%] = 4.8
Molar Density @ atm. [kmol/m3] = 0.04160
Absolute Permeability [darcies] = 11.0200
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	21.1	0.0	0.019	0.000	0.00	1.00	1.00	0.09	0.00	0.00	0.047
1.30	1.00	0.0	84.4	0.076	0.002	9.50	65.50	66.50	6.30	0.15	0.03	0.776
1.10	1.00	21.1	0.0	0.019	0.000	0.00	1.20	67.70	6.42	0.00	0.00	0.057
1.10	1.00	0.0	84.4	0.076	0.000	5.00	52.00	119.70	11.35	0.10	0.00	0.616
1.10	1.00	21.1	0.0	0.019	0.004	0.00	8.00	127.70	12.10	0.00	0.50	0.380
1.10	1.00	0.0	84.4	0.076	0.052	42.80	40.20	167.90	15.91	1.06	1.29	0.476
1.00	1.00	21.1	0.0	0.019	0.010	4.20	2.10	170.00	16.11	2.00	4.76	0.100
1.10	1.00	0.0	84.6	0.076	0.055	53.50	23.30	193.30	18.32	2.30	2.36	0.275
1.10	1.00	21.1	0.0	0.019	0.003	2.00	2.00	195.30	18.51	1.00	1.50	0.095
1.10	1.00	0.0	84.1	0.076	0.058	65.50	15.50	210.80	19.98	4.23	3.74	0.184
1.10	1.00	21.1	0.0	0.019	0.002	5.50	2.00	212.80	20.17	2.75	1.00	0.095
1.10	1.00	0.0	84.4	0.076	0.031	68.00	11.00	223.80	21.21	6.18	2.82	0.130
1.10	1.00	21.1	0.0	0.019	0.013	4.00	1.50	225.30	21.36	2.67	8.67	0.071
1.10	1.00	0.0	84.4	0.076	0.121	71.50	7.00	232.30	22.02	10.21	17.29	0.083
1.10	1.00	21.2	0.0	0.019	0.031	2.00	1.00	233.30	22.11	2.00	31.00	0.047
1.10	1.00	0.0	84.5	0.076	0.141	72.00	7.00	240.30	22.78	10.29	20.14	0.083
1.10	1.00	21.2	0.0	0.019	0.039	11.50	1.50	241.80	22.92	7.67	26.00	0.071

TABLE A32 (CONTINUED)

RESULTS OF RUN 1DT32
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.090 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 35.6
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 6.42

Pore Volume [cm3] = 1108.0
Initial Oil Saturation [%] = 95.2
Hydrocarbon Pore Volume [cm3] = 1055.0
Carbon Dioxide Retention [%inj] = 14.44

Connate Water Saturation [%] = 4.8
Molar Density @ atm. [kmol/m3] = 0.04160
Absolute Permeability [darcies] = 11.0200
Average Flow Velocity [m/d] = 0.984

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	84.4	0.076	0.121	******	6.20	248.00	23.51	*****	19.52	0.073
1.10	1.00	21.2	0.0	0.019	0.068	15.00	2.00	250.00	23.70	7.50	34.00	0.095
1.10	1.00	0.0	84.4	0.076	0.129	70.50	4.30	254.30	24.10	16.40	30.00	0.051
1.10	1.00	0.0	252.8	0.228	0.310	215.00	35.00	289.30	27.42	6.14	8.86	0.138
1.10	1.00	0.0	251.3	0.227	0.227	226.00	22.00	311.30	29.51	10.27	10.32	0.088
1.10	1.00	0.0	250.1	0.226	0.126	227.00	21.50	332.80	31.54	10.56	5.86	0.086
1.10	1.00	0.0	253.9	0.229	0.120	241.00	9.50	342.30	32.45	25.37	12.63	0.037
1.10	1.00	0.0	253.6	0.229	0.114	240.00	8.20	350.50	33.22	29.27	13.90	0.032
0.01	0.01	0.0	0.0	0.000	0.284	96.00	25.00	375.50	35.59	3.84	11.36	

TABLE A33

RESULTS OF RUN 2DT1
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.152 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 40.8
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.58

Pore Volume [cm3] = 1986.0
Initial Oil Saturation [%] = 88.8
Hydrocarbon Pore Volume [cm3] = 1764.0
Carbon Dioxide Retention [%inj] = 56.89

Connate Water Saturation [%] = 11.2
Molar Density @ atm. [kmol/m3] = 0.04165
Absolute Permeability [darcies] = 11.1800
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	35.2	0.0	0.018	0.000	0.00	2.00	2.00	0.11	0.00	0.00	0.057
1.10	1.00	0.0	141.1	0.071	0.002	2.00	130.00	132.00	7.48	0.02	0.02	0.921
1.30	1.00	35.2	0.0	0.018	0.000	0.50	13.00	145.00	8.22	0.04	0.00	0.369
1.30	1.00	0.0	141.1	0.071	0.000	4.00	126.00	271.00	15.36	0.03	0.00	0.893
1.20	1.00	35.2	0.0	0.018	0.000	4.00	11.90	282.90	16.04	0.34	0.00	0.338
1.20	1.00	0.0	141.1	0.071	0.004	44.00	83.00	365.90	20.74	0.53	0.05	0.588
1.10	1.00	35.2	0.0	0.018	0.000	13.40	10.50	376.40	21.34	1.28	0.00	0.298
1.30	1.00	0.0	142.4	0.072	0.005	71.00	48.00	424.40	24.06	1.48	0.10	0.337
1.20	1.00	35.2	0.0	0.018	0.003	18.00	6.90	431.30	24.45	2.61	0.43	0.196
1.30	1.00	0.0	141.4	0.071	0.002	87.00	35.00	466.30	26.43	2.49	0.06	0.248
1.20	1.00	35.2	0.0	0.018	0.000	19.30	3.30	469.60	26.62	5.85	0.00	0.094
1.20	1.00	0.0	141.1	0.071	0.004	98.50	22.00	491.60	27.87	4.48	0.18	0.156
1.20	1.00	35.2	0.0	0.018	0.000	29.60	5.10	496.70	28.16	5.80	0.00	0.145
1.20	1.00	0.0	141.1	0.071	0.004	93.00	18.00	514.70	29.18	5.17	0.22	0.128
1.30	1.00	35.2	0.0	0.018	0.000	28.80	4.70	519.40	29.44	6.13	0.00	0.133
1.10	1.00	0.0	141.1	0.071	0.020	89.80	22.00	541.40	30.69	4.08	0.91	0.156
1.10	1.00	35.2	0.0	0.018	0.002	35.00	7.60	549.00	31.12	4.61	0.26	0.216

TABLE A33 (CONTINUED)

RESULTS OF RUN 2DT1
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.152 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 40.8
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.58

Pore Volume [cm3] = 1986.0
Initial Oil Saturation [%] = 88.8
Hydrocarbon Pore Volume [cm3] = 1764.0
Carbon Dioxide Retention [%inj] = 56.89

Connate Water Saturation [%] = 11.2
Molar Density @ atm. [kmol/m3] = 0.04165
Absolute Permeability [darcies] = 11.1800
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	141.1	0.071	0.017	83.00	22.00	571.00	32.37	3.77	0.77	0.156
1.30	1.00	35.2	0.0	0.018	0.006	26.00	7.10	578.10	32.77	3.66	0.85	0.202
1.20	1.00	0.0	141.1	0.071	0.157	83.00	29.00	607.10	34.42	2.86	5.41	0.205
1.10	1.00	0.0	255.3	0.129	0.039	204.00	45.50	652.60	37.00	4.48	0.86	0.178
1.10	1.00	0.0	252.3	0.127	0.062	223.00	28.50	681.10	38.61	7.82	2.18	0.113
1.20	1.00	0.0	252.4	0.127	0.160	227.00	25.00	706.10	40.03	9.08	6.40	0.099
1.20	1.00	0.0	251.6	0.127	0.230	233.00	18.50	724.60	41.08	12.59	12.43	0.074
1.20	1.00	0.0	253.9	0.128	0.176	233.00	19.00	743.60	42.15	12.26	9.26	0.075
1.20	1.00	0.0	254.5	0.128	0.168	238.00	13.00	756.60	42.89	18.31	12.92	0.051
0.01	0.01	0.0	0.0	0.000	0.860	130.00	41.80	798.40	45.26	3.11	20.57	

TABLE A34

RESULTS OF RUN 2DTO2

[0.20 HCPV CO2-N2 @ 1.0 MPa (0.150 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 40.1
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.64

Pore Volume [cm3] = 1955.0
Initial Oil Saturation [%] = 89.5
Hydrocarbon Pore Volume [cm3] = 1750.0
Carbon Dioxide Retention [%inj] = 44.74

Connate Water Saturation [%] = 11.1
Molar Density @ atm. [kmol/m3] = 0.04163
Absolute Permeability [darcies] = 10.4900
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	35.0	0.0	0.018	0.004	0.00	3.50	3.50	0.20	0.00	1.14	0.100
1.30	1.00	0.0	140.0	0.072	0.007	2.50	130.00	133.50	7.63	0.02	0.05	0.929
1.20	1.00	35.0	0.0	0.018	0.024	0.00	17.20	150.70	8.61	0.00	1.40	0.492
1.50	1.00	0.0	140.0	0.072	0.007	12.40	113.50	264.20	15.10	0.11	0.06	0.811
1.40	1.00	35.0	0.0	0.018	0.000	8.00	16.50	280.70	16.04	0.48	0.00	0.472
1.30	1.00	0.0	140.0	0.072	0.010	50.00	72.00	352.70	20.15	0.69	0.14	0.514
1.20	1.00	35.0	0.0	0.018	0.000	18.00	15.00	367.70	21.01	1.20	0.00	0.429
1.20	1.00	0.0	140.0	0.072	0.016	55.00	56.00	423.70	24.21	0.98	0.29	0.400
1.30	1.00	35.0	0.0	0.018	0.000	29.50	8.10	431.80	24.67	3.64	0.00	0.232
1.20	1.00	0.0	141.5	0.072	0.110	72.00	38.00	469.80	26.85	1.89	2.89	0.269
1.20	1.00	35.0	0.0	0.018	0.009	31.30	7.70	477.50	27.29	4.06	1.17	0.220
1.10	1.00	0.0	140.0	0.072	0.169	82.00	27.00	504.50	28.83	3.04	6.26	0.193
1.10	1.00	35.0	0.0	0.018	0.018	29.70	6.30	510.80	29.19	4.71	2.86	0.180
1.10	1.00	0.0	140.0	0.072	0.164	80.50	26.00	536.80	30.67	3.10	6.31	0.186
1.10	1.00	35.0	0.0	0.018	0.038	32.00	5.50	542.30	30.99	5.82	6.91	0.157
1.10	1.00	0.0	140.0	0.072	0.164	103.00	21.00	563.30	32.19	4.90	7.81	0.150
1.10	1.00	35.0	0.0	0.018	0.019	27.00	4.70	568.00	32.46	5.74	4.04	0.134

TABLE A34 (CONTINUED)

RESULTS OF RUN 2DT02
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.150 g-mol) 4:1 WAG, 10 Slugs, DEAD OIL]

Porosity [%] = 40.1
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.64

Pore Volume [cm3] = 1955.0
Initial Oil Saturation [%] = 89.5
Hydrocarbon Pore Volume [cm3] = 1750.0
Carbon Dioxide Retention [%inj] = 44.74

Connate Water Saturation [%] = 11.1
Molar Density @ atm. [kmol/m3] = 0.04163
Absolute Permeability [darcies] = 10.4900
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	140.0	0.072	0.158	88.20	19.00	587.00	33.54	4.64	8.32	0.136
1.10	1.00	35.0	0.0	0.018	0.013	33.50	4.00	591.00	33.77	8.38	3.25	0.114
1.10	1.00	0.0	140.0	0.072	0.223	90.00	17.00	608.00	34.74	5.29	13.12	0.121
1.10	1.00	0.0	277.4	0.142	0.172	226.50	25.00	633.00	36.17	9.06	6.88	0.090
1.10	1.00	0.0	257.4	0.132	0.126	223.00	32.00	665.00	38.00	6.97	3.94	0.124
1.10	1.00	0.0	256.6	0.131	0.149	232.00	19.50	684.50	39.11	11.90	7.64	0.076
1.10	1.00	0.0	249.7	0.128	0.153	234.00	17.00	701.50	40.09	13.76	9.00	0.068
1.10	1.00	0.0	309.1	0.158	0.069	289.00	20.00	721.50	41.23	14.45	3.45	0.065
1.10	1.00	0.0	253.2	0.130	0.095	241.00	12.00	733.50	41.91	20.08	7.92	0.047
0.01	0.01	0.0	0.0	0.000	0.485	168.50	51.00	784.50	44.83	3.30	9.51	

TABLE A35

RESULTS OF RUN 2DT03

[0.20 HCPV CO2-N2 @ 1.0 MPa (0.148 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 39.5
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.66

Pore Volume [cm3] = 1923.0
Initial Oil Saturation [%] = 89.9
Hydrocarbon Pore Volume [cm3] = 1727.5
Carbon Dioxide Retention [%inj] = 41.51

Connate Water Saturation [%] = 11.2
Molar Density @ atm. [kmol/m3] = 0.04162
Absolute Permeability [darcies] = 10.0700
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	34.5	0.0	0.018	0.000	0.00	3.50	3.50	0.20	0.00	0.00	0.101
1.30	1.00	0.0	138.2	0.072	0.015	0.00	128.50	132.00	7.64	0.00	0.12	0.930
1.20	1.00	34.5	0.0	0.018	0.000	0.00	21.80	153.80	8.90	0.00	0.00	0.632
1.30	1.00	0.0	138.2	0.072	0.010	7.75	108.75	262.55	15.20	0.07	0.09	0.787
1.30	1.00	34.5	0.0	0.018	0.001	5.00	13.20	275.75	15.96	0.38	0.08	0.383
1.20	1.00	0.0	138.2	0.072	0.089	32.50	89.00	364.75	21.11	0.37	1.00	0.644
1.20	1.00	34.5	0.0	0.018	0.004	8.00	15.00	379.75	21.98	0.53	0.27	0.435
1.20	1.00	0.0	138.2	0.072	0.190	51.00	57.00	436.75	25.28	0.89	3.33	0.412
1.20	1.00	34.5	0.0	0.018	0.000	18.70	6.80	443.55	25.68	2.75	0.00	0.197
1.20	1.00	0.0	138.2	0.072	0.138	74.00	39.20	482.75	27.94	1.89	3.52	0.284
1.20	1.00	34.5	0.0	0.018	0.000	23.00	6.20	488.95	28.30	3.71	0.00	0.180
1.10	1.00	0.0	138.2	0.072	0.213	84.00	28.00	516.95	29.92	3.00	7.61	0.203
1.10	1.00	34.5	0.0	0.018	0.007	27.60	5.00	521.95	30.21	5.52	1.40	0.145
1.10	1.00	0.0	138.2	0.072	0.252	77.00	27.50	549.45	31.81	2.80	9.16	0.199
1.10	1.00	34.5	0.0	0.018	0.010	26.50	4.50	553.95	32.07	5.89	2.22	0.130
1.10	1.00	0.0	138.2	0.072	0.166	91.00	21.00	574.95	33.28	4.33	7.90	0.152
1.10	1.00	34.5	0.0	0.018	0.014	25.00	4.50	579.45	33.54	5.56	3.11	0.130

TABLE A35 (CONTINUED)

RESULTS OF RUN 2DT03
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.148 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 39.5
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.66

Pore Volume [cm3] = 1923.0
Initial Oil Saturation [%] = 89.9
Hydrocarbon Pore Volume [cm3] = 1727.5
Carbon Dioxide Retention [%inj] = 41.51

Connate Water Saturation [%] = 11.2
Molar Density @ atm. [kmol/m3] = 0.04162
Absolute Permeability [darcies] = 10.0700
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM JIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	138.2	0.072	0.279	89.00	29.00	608.45	35.22	3.07	9.62	0.210
1.10	1.00	34.5	0.0	0.018	0.021	35.50	4.90	613.35	35.51	7.24	4.29	0.142
1.10	1.00	0.0	138.2	0.072	0.303	85.00	21.00	634.35	36.72	4.05	14.43	0.152
1.10	1.00	0.0	258.0	0.134	0.082	230.50	20.00	654.35	37.88	11.52	4.10	0.078
1.10	1.00	0.0	250.6	0.130	0.079	229.50	20.50	674.85	39.07	11.20	3.85	0.082
1.10	1.00	0.0	250.5	0.130	0.094	233.00	19.00	693.85	40.16	12.26	4.95	0.076
1.10	1.00	0.0	254.8	0.133	0.094	237.00	16.00	709.85	41.09	14.81	5.87	0.063
1.10	1.00	0.0	250.6	0.130	0.078	238.50	14.50	724.35	41.93	16.45	5.38	0.058
1.10	1.00	0.0	256.5	0.133	0.071	243.00	13.00	737.35	42.68	18.69	5.46	0.051
0.01	0.01	0.0	0.0	0.000	0.253	118.00	34.00	771.35	44.65	3.47	7.44	

TABLE A36

RESULTS OF RUN 2DT04
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.139 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 37.2
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.75

Pore Volume [cm3] = 1810.0
Initial Oil Saturation [%] = 90.1
Hydrocarbon Pore Volume [cm3] = 1648.5
Carbon Dioxide Retention [%inj] = 38.70

Connate Water Saturation [%] = 12.8
Molar Density @ atm. [kmol/m3] = 0.04160
Absolute Permeability [darcies] = 9.8600
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	32.6	0.0	0.018	0.000	0.00	1.50	1.50	0.09	0.00	0.00	0.046
1.50	1.00	0.0	130.5	0.072	0.005	3.00	118.00	119.50	7.25	0.03	0.04	0.904
1.20	1.00	32.6	0.0	0.018	0.000	0.00	15.00	134.50	8.16	0.00	0.00	0.461
1.30	1.00	0.0	130.5	0.072	0.001	8.00	107.00	241.50	14.65	0.07	0.01	0.820
1.30	1.00	32.6	0.0	0.018	0.000	8.50	10.50	252.00	15.29	0.81	0.00	0.322
1.10	1.00	0.0	130.5	0.072	0.000	38.00	77.20	329.20	19.97	0.49	0.00	0.591
1.20	1.00	32.6	0.0	0.018	0.000	13.50	7.50	336.70	20.42	1.80	0.00	0.230
1.20	1.00	0.0	130.5	0.072	0.016	68.50	44.00	380.70	23.09	1.56	0.36	0.337
1.20	1.00	32.6	0.0	0.018	0.004	19.00	6.50	387.20	23.49	2.92	0.62	0.200
1.10	1.00	0.0	130.5	0.072	0.077	74.00	36.00	423.20	25.67	2.06	2.14	0.276
1.20	1.00	32.6	0.0	0.018	0.011	22.00	5.80	429.00	26.02	3.79	1.90	0.178
1.10	1.00	0.0	130.5	0.072	0.120	78.00	29.80	458.80	27.83	2.62	4.03	0.228
1.10	1.00	32.6	0.0	0.018	0.019	25.00	5.70	464.50	28.18	4.39	3.33	0.175
1.10	1.00	0.0	130.5	0.072	0.171	82.00	26.50	491.00	29.78	3.09	6.45	0.203
1.10	1.00	32.6	0.0	0.018	0.024	24.00	4.00	495.00	30.03	6.00	6.00	0.123
1.10	1.00	0.0	130.5	0.072	0.194	87.00	18.00	513.00	31.12	4.83	10.78	0.138
1.10	1.00	32.6	0.0	0.018	0.035	30.50	4.30	517.30	31.38	7.09	8.14	0.132

TABLE A36 (CONTINUED)

RESULTS OF RUN 2DT04

[0.20 HCPV CO2-N2 @ 1.0 MPa (0.139 g-mol) 4:1 WAG, 10 Slugs, DEAD OIL]

Porosity [%] = 37.2
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.75

Pore Volume [cm3] = 1810.0
Initial Oil Saturation [%] = 90.1
Hydrocarbon Pore Volume [cm3] = 1648.5
Carbon Dioxide Retention [%inj] = 38.70

Connate Water Saturation [%] = 12.8
Molar Density @ atm. [kmol/m3] = 0.04160
Absolute Permeability [darcies] = 9.8600
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	130.5	0.072	0.266	89.70	16.00	533.30	32.35	5.61	16.62	0.123
1.10	1.00	32.6	0.0	0.018	0.037	26.00	3.00	536.30	32.53	8.67	12.33	0.092
1.10	1.00	0.0	130.5	0.072	0.256	85.00	15.00	551.30	33.44	5.67	17.07	0.115
1.10	1.00	0.0	255.5	0.141	0.292	226.00	26.00	577.30	35.02	8.69	11.23	0.102
1.10	1.00	0.0	261.6	0.145	0.180	234.50	15.50	592.80	35.96	15.13	11.61	0.059
1.10	1.00	0.0	253.1	0.140	0.135	234.00	16.00	608.80	36.93	14.63	8.44	0.063
1.10	1.00	0.0	252.2	0.139	0.087	234.00	17.00	625.80	37.96	13.76	5.12	0.067
1.10	1.00	0.0	250.0	0.138	0.064	236.00	13.00	638.80	38.75	18.15	4.92	0.052
1.10	1.00	0.0	250.9	0.139	0.050	240.00	12.00	650.80	39.48	20.00	4.17	0.048
0.01	0.01	0.0	0.0	0.000	0.633	115.50	40.50	691.30	41.94	2.85	15.63	

TABLE A37

RESULTS OF RUN 2DT05
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.142 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 38.0
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.87

Pore Volume [cm3] = 1851.0
Initial Oil Saturation [%] = 89.9
Hydrocarbon Pore Volume [cm3] = 1665.0
Carbon Dioxide Retention [%inj] = 38.54

Connate Water Saturation [%] = 14.0
Molar Density @ atm. [kmol/m3] = 0.04159
Absolute Permeability [darcies] = 10.0500
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	33.3	0.0	0.018	0.000	0.00	1.50	1.50	0.09	0.00	0.00	0.045
1.50	1.00	0.0	133.2	0.072	0.004	3.00	121.00	122.50	7.36	0.02	0.03	0.908
1.20	1.00	33.3	0.0	0.018	0.001	0.00	9.00	131.50	7.90	0.00	0.11	0.271
1.50	1.00	0.0	133.2	0.072	0.000	11.80	108.00	239.50	14.38	0.11	0.00	0.811
1.30	1.00	33.3	0.0	0.018	0.000	13.00	10.00	249.50	14.98	1.30	0.00	0.301
1.20	1.00	0.0	133.2	0.072	0.052	38.50	78.00	327.50	19.67	0.49	0.67	0.586
1.20	1.00	33.3	0.0	0.018	0.000	20.50	3.00	330.50	19.85	6.83	0.00	0.090
1.10	1.00	0.0	133.2	0.072	0.139	56.00	51.00	381.50	22.91	1.10	2.73	0.383
1.20	1.00	33.3	0.0	0.018	0.005	17.30	2.00	383.50	23.03	8.65	2.50	0.060
1.20	1.00	0.0	133.2	0.072	0.090	66.00	51.00	434.50	26.10	1.29	1.76	0.383
1.20	1.00	33.3	0.0	0.018	0.006	20.00	2.00	436.50	26.22	10.00	3.00	0.060
1.20	1.00	0.0	133.2	0.072	0.135	80.00	33.00	469.50	28.20	2.42	4.09	0.248
1.10	1.00	33.3	0.0	0.018	0.075	35.50	3.00	472.50	28.38	11.83	25.00	0.090
1.10	1.00	0.0	133.2	0.072	0.262	70.00	27.00	499.50	30.00	2.59	9.70	0.203
1.20	1.00	33.3	0.0	0.018	0.014	20.00	2.00	501.50	30.12	10.00	7.00	0.060
1.10	1.00	0.0	132.2	0.071	0.178	87.50	26.00	527.50	31.68	3.37	6.85	0.197
1.20	1.00	33.3	0.0	0.018	0.021	30.20	1.80	529.30	31.79	16.78	11.67	0.054

TABLE A37 (CONTINUED)

RESULTS OF RUN 2DT05
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.142 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 38.0
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.87

Pore Volume [cm3] = 1851.0
Initial Oil Saturation [%] = 89.9
Hydrocarbon Pore Volume [cm3] = 1665.0
Carbon Dioxide Retention [%inj] = 38.54

Connate Water Saturation [%] = 14.0
Molar Density @ atm. [kmol/m3] = 0.04159
Absolute Permeability [darcies] = 10.0500
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	130.2	0.070	0.263	82.00	24.00	553.30	33.23	3.42	10.96	0.184
1.10	1.00	33.3	0.0	0.018	0.070	36.70	2.50	555.80	33.38	14.68	28.00	0.075
1.10	1.00	0.0	133.2	0.072	0.354	73.50	14.00	569.80	34.22	5.25	25.29	0.105
1.10	1.00	0.0	250.7	0.135	0.153	227.00	26.00	595.80	35.78	8.73	5.88	0.104
1.10	1.00	0.0	260.9	0.141	0.111	234.00	20.00	615.80	36.98	11.70	5.55	0.077
1.10	1.00	0.0	256.6	0.139	0.085	233.00	19.00	634.80	38.13	12.26	4.47	0.074
1.10	1.00	0.0	248.1	0.134	0.068	234.00	16.00	650.80	39.09	14.63	4.25	0.064
1.10	1.00	0.0	249.2	0.135	0.061	235.00	15.00	665.80	39.99	15.67	4.07	0.060
1.10	1.00	0.0	249.8	0.135	0.051	235.00	14.00	679.80	40.83	16.79	3.64	0.056
1.10	1.00	0.0	252.2	0.136	0.036	240.00	10.00	689.80	41.43	24.00	3.60	0.040
0.01	0.01	0.0	0.0	0.000	0.294	131.00	14.90	704.70	42.32	8.79	19.73	

TABLE A38

RESULTS OF RUN 2DT06
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.146 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 38.3
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.95

Pore Volume [cm3] = 1863.0
Initial Oil Saturation [%] = 92.3
Hydrocarbon Pore Volume [cm3] = 1719.5
Carbon Dioxide Retention [%inj] = 38.52

Connate Water Saturation [%] = 7.7
Molar Density @ atm. [kmol/m3] = 0.04237
Absolute Permeability [darcies] = 12.9600
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	34.4	0.0	0.018	0.001	0.00	1.50	1.50	0.09	0.00	0.67	0.044
1.10	1.00	0.0	137.6	0.074	0.006	2.00	124.00	125.50	7.30	0.02	0.05	0.901
1.20	1.00	34.4	0.0	0.018	0.000	0.00	9.00	134.50	7.82	0.00	0.00	0.262
1.60	1.00	0.0	137.6	0.074	0.001	2.00	126.00	260.50	15.15	0.02	0.01	0.916
1.20	1.00	34.4	0.0	0.018	0.000	1.00	10.00	270.50	15.73	0.10	0.00	0.291
1.30	1.00	0.0	137.6	0.074	0.052	32.00	97.50	368.00	21.40	0.33	0.53	0.709
1.10	1.00	34.4	0.0	0.018	0.000	3.00	3.00	371.00	21.58	1.00	0.00	0.087
1.10	1.00	0.0	137.6	0.074	0.140	75.00	56.00	427.00	24.83	1.34	2.50	0.407
1.10	1.00	34.4	0.0	0.018	0.016	5.00	2.00	429.00	24.95	2.50	8.00	0.058
1.10	1.00	0.0	137.6	0.074	0.100	91.50	36.50	465.50	27.07	2.51	2.74	0.265
1.10	1.00	34.4	0.0	0.018	0.000	2.50	2.00	467.50	27.19	1.25	0.00	0.058
1.10	1.00	0.0	137.6	0.074	0.122	100.00	31.00	498.50	28.99	3.23	3.94	0.225
1.10	1.00	34.4	0.0	0.018	0.008	8.00	3.00	501.50	29.17	2.67	2.67	0.087
1.10	1.00	0.0	137.6	0.074	0.290	94.00	23.80	525.30	30.55	3.95	12.18	0.173
1.10	1.00	34.4	0.0	0.018	0.001	10.20	2.00	527.30	30.67	5.10	0.50	0.058
1.10	1.00	0.0	137.6	0.074	0.165	100.00	24.00	551.30	32.06	4.17	6.88	0.174
1.10	1.00	34.4	0.0	0.018	0.000	12.00	1.80	553.10	32.17	6.67	0.00	0.052

TABLE A38 (CONTINUED)

RESULTS OF RUN 2DT06

[0.20 HCPV CO2-N2 @ 1.0 MPa (0.146 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 38.3
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.95

Pore Volume [cm3] = 1863.0
Initial Oil Saturation [%] = 92.3
Hydrocarbon Pore Volume [cm3] = 1719.5
Carbon Dioxide Retention [%inj] = 38.52

Connate Water Saturation [%] = 7.7
Molar Density @ atm. [kmol/m3] = 0.04237
Absolute Permeability [darcies] = 12.9600
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	137.6	0.074	0.280	105.00	17.00	570.10	33.15	6.18	16.47	0.124
1.10	1.00	34.4	0.0	0.018	0.000	5.00	1.50	571.60	33.24	3.33	0.00	0.044
1.10	1.00	0.0	137.6	0.074	0.333	112.50	14.00	585.60	34.06	8.04	23.79	0.102
1.10	1.00	0.0	507.1	0.272	0.278	456.00	46.50	632.10	36.76	9.81	5.98	0.092
1.10	1.00	0.0	251.7	0.135	0.078	230.50	18.00	650.10	37.81	12.81	4.33	0.072
1.20	1.00	0.0	254.4	0.137	0.070	239.00	16.00	666.10	38.74	14.94	4.37	0.063
1.20	1.00	0.0	251.0	0.135	0.062	240.00	11.00	677.10	39.38	21.82	5.64	0.044
1.20	1.00	0.0	247.7	0.133	0.058	238.50	11.50	688.60	40.05	20.74	5.04	0.046
1.20	1.00	0.0	248.0	0.133	0.044	240.50	10.50	699.10	40.66	22.90	4.19	0.042
0.01	0.01	0.0	0.0	0.000	0.333	119.50	16.00	715.10	41.59	7.47	20.81	

TABLE A39

RESULTS OF RUN 2DT07
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.151 g-mol) 4:1 WAG, 10 Slugs, DEAD OIL]

Porosity [%] = 40.4
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.56

Pore Volume [cm3] = 1970.0
Initial Oil Saturation [%] = 89.0
Hydrocarbon Pore Volume [cm3] = 1753.0
Carbon Dioxide Retention [%inj] = 57.13

Connate Water Saturation [%] = 11.8
Molar Density @ atm. [kmol/m3] = 0.04165
Absolute Permeability [darcies] = 11.0200
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	35.0	0.0	0.018	0.000	0.00	2.00	2.00	0.11	0.00	0.00	0.057
1.30	1.00	0.0	140.2	0.071	0.000	0.00	128.00	130.00	7.42	0.00	0.00	0.913
1.20	1.00	35.0	0.0	0.018	0.000	0.00	22.00	152.00	8.67	0.00	0.00	0.628
1.20	1.00	0.0	140.2	0.071	0.001	10.00	110.00	262.00	14.95	0.09	0.01	0.784
1.40	1.00	35.0	0.0	0.018	0.000	9.00	14.00	276.00	15.74	0.64	0.00	0.400
1.20	1.00	0.0	140.3	0.071	0.034	45.00	71.00	347.00	19.79	0.63	0.48	0.506
1.30	1.00	35.0	0.0	0.018	0.007	19.00	10.30	357.30	20.38	1.84	0.68	0.294
1.20	1.00	0.0	140.3	0.071	0.136	70.00	41.00	398.30	22.72	1.71	3.32	0.292
1.30	1.00	35.0	0.0	0.018	0.013	25.00	7.50	405.80	23.15	3.33	1.73	0.214
1.30	1.00	0.0	140.2	0.071	0.200	69.00	42.00	447.80	25.54	1.64	4.76	0.299
1.20	1.00	35.0	0.0	0.018	0.025	24.00	8.20	456.00	26.01	2.93	3.05	0.234
1.10	1.00	0.0	140.2	0.071	0.245	77.00	30.00	486.00	27.72	2.57	8.17	0.214
1.10	1.00	35.0	0.0	0.018	0.032	24.20	8.00	494.00	28.18	3.02	4.00	0.228
1.10	1.00	0.0	140.3	0.071	0.329	84.00	22.00	516.00	29.44	3.82	14.95	0.157
1.10	1.00	35.0	0.0	0.018	0.035	25.00	7.50	523.50	29.86	3.33	4.67	0.214
1.10	1.00	0.0	140.2	0.071	0.246	84.00	26.00	549.50	31.35	3.23	9.46	0.185
1.10	1.00	35.0	0.0	0.018	0.036	24.50	7.50	557.00	31.77	3.27	4.80	0.214

TABLE A39 (CONTINUED)

RESULTS OF RUN 2DT07
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.151 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 40.4
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.56

Pore Volume [cm3] = 1970.0
Initial Oil Saturation [%] = 89.0
Hydrocarbon Pore Volume [cm3] = 1753.0
Carbon Dioxide Retention [%inj] = 57.13

Connate Water Saturation [%] = 11.8
Molar Density @ atm. [kmol/m3] = 0.04165
Absolute Permeability [darcies] = 11.0200
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	140.3	0.071	0.256	85.00	25.00	582.00	33.20	3.40	10.24	0.178
1.10	1.00	35.0	0.0	0.018	0.051	30.00	7.40	589.40	33.62	4.05	6.89	0.211
1.10	1.00	0.0	140.3	0.071	0.224	84.00	23.00	612.40	34.93	3.65	9.74	0.164
1.10	1.00	0.0	257.6	0.131	0.235	220.00	32.00	644.40	36.76	6.88	7.34	0.124
1.10	1.00	0.0	250.9	0.127	0.173	225.00	26.00	670.40	38.24	8.65	6.65	0.104
1.10	1.00	0.0	252.2	0.128	0.115	236.00	18.00	688.40	39.27	13.11	6.39	0.071
1.10	1.00	0.0	262.9	0.133	0.075	240.00	22.00	710.40	40.52	10.91	3.41	0.084
1.10	1.00	0.0	259.8	0.132	0.048	242.00	18.00	728.40	41.55	13.44	2.67	0.069
1.10	1.00	0.0	250.2	0.127	0.030	238.00	14.00	742.40	42.35	17.00	2.14	0.056
0.01	0.01	0.0	0.0	0.000	0.172	80.00	48.00	790.40	45.09	1.67	3.58	

TABLE A40

RESULTS OF RUN 2DT08

[0.20 HCPV CO2-N2 @ 1.2 MPa (0.168 g-mol) 4:1 WAG, 10 Slugs, DEAD OIL]

Porosity [%] = 37.7
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 3.60

Pore Volume [cm3] = 1837.0
Initial Oil Saturation [%] = 88.1
Hydrocarbon Pore Volume [cm3] = 1618.5
Carbon Dioxide Retention [%inj] = 56.01

Connate Water Saturation [%] = 11.9
Molar Density @ atm. [kmol/m3] = 0.06201
Absolute Permeability [darcies] = 11.6100
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.30	1.20	32.3	0.0	0.018	0.000	0.00	1.80	1.80	0.11	0.00	0.00	0.056
1.40	1.20	0.0	129.5	0.070	0.001	1.00	128.00	129.80	8.02	0.01	0.01	0.988
1.40	1.20	32.3	0.0	0.018	0.000	0.00	12.00	141.80	8.76	0.00	0.00	0.371
1.80	1.20	0.0	129.4	0.070	0.002	5.00	116.00	257.80	15.93	0.04	0.02	0.896
1.40	1.20	32.3	0.0	0.018	0.000	1.00	10.90	268.70	16.60	0.09	0.00	0.337
1.50	1.20	0.0	129.5	0.070	0.000	43.00	76.20	344.90	21.31	0.56	0.00	0.589
1.30	1.20	32.3	0.0	0.018	0.000	5.50	9.60	354.50	21.90	0.57	0.00	0.297
1.30	1.20	0.0	129.5	0.070	0.000	74.00	56.20	410.70	25.38	1.32	0.00	0.434
1.30	1.20	32.3	0.0	0.018	0.000	6.70	6.30	417.00	25.76	1.06	0.00	0.195
1.40	1.20	0.0	129.4	0.070	0.000	93.00	42.00	459.00	28.36	2.21	0.00	0.324
1.30	1.20	32.3	0.0	0.018	0.000	14.40	4.10	463.10	28.61	3.51	0.00	0.127
1.50	1.20	0.0	129.4	0.070	0.000	92.50	37.20	500.30	30.91	2.49	0.00	0.287
1.30	1.20	32.3	0.0	0.018	0.000	18.00	4.70	505.00	31.20	3.83	0.00	0.145
1.30	1.20	0.0	129.4	0.070	0.001	88.00	31.10	536.10	33.12	2.83	0.03	0.240
1.30	1.20	32.3	0.0	0.018	0.002	20.00	4.30	540.40	33.39	4.65	0.47	0.133
1.30	1.20	0.0	129.4	0.070	0.035	90.50	20.00	560.40	34.62	4.52	1.75	0.154
1.30	1.20	32.3	0.0	0.018	0.006	15.00	7.00	567.40	35.06	2.14	0.86	0.217

TABLE A40 (CONTINUED)

RESULTS OF RUN 2DT08
[0.20 HCPV CO2-N2 @ 1.2 MPa (0.168 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 37.7
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 3.60

Pore Volume [cm3] = 1837.0
Initial Oil Saturation [%] = 88.1
Hydrocarbon Pore Volume [cm3] = 1618.5
Carbon Dioxide Retention [%inj] = 56.01

Connate Water Saturation [%] = 11.9
Molar Density @ atm. [kmol/m3] = 0.06201
Absolute Permeability [darcies] = 11.6100
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.30	1.20	0.0	129.4	0.070	0.113	94.00	20.20	587.60	36.31	4.65	5.59	0.156
1.30	1.20	32.3	0.0	0.018	0.015	27.00	6.50	594.10	36.71	4.15	2.31	0.201
1.30	1.20	0.0	129.4	0.070	0.215	85.00	27.00	621.10	38.37	3.15	7.96	0.209
1.30	1.20	0.0	263.9	0.144	0.144	228.00	22.50	643.60	39.77	10.13	6.40	0.085
1.30	1.20	0.0	248.9	0.135	0.121	227.00	22.00	665.60	41.12	10.32	5.50	0.088
1.30	1.20	0.0	248.9	0.135	0.106	233.00	18.00	683.60	42.24	12.94	5.89	0.072
1.30	1.20	0.0	250.3	0.136	0.075	232.00	17.00	700.60	43.29	13.65	4.41	0.068
1.30	1.20	0.0	250.4	0.136	0.060	238.00	16.00	716.60	44.28	14.88	3.75	0.064
1.30	1.20	0.0	253.6	0.138	0.054	241.00	13.00	729.60	45.08	18.54	4.15	0.051
1.30	1.20	0.0	249.1	0.136	0.043	236.50	14.00	743.60	45.94	16.89	3.07	0.056
1.30	1.20	0.0	251.1	0.137	0.044	230.00	21.00	764.60	47.24	10.95	2.10	0.084
1.30	1.20	0.0	253.3	0.138	0.052	234.00	18.00	782.60	48.35	13.00	2.89	0.071
1.30	1.20	0.0	249.9	0.136	0.061	236.00	14.00	796.60	49.22	16.86	4.36	0.056
1.30	1.20	0.0	250.3	0.136	0.043	240.00	10.00	806.60	49.84	24.00	4.30	0.040
0.01	0.01	0.0	0.0	0.000	0.146	135.00	39.00	845.60	52.25	3.46	3.74	

TABLE A41

RESULTS OF RUN 2DT09
[0.20 HCPV CO2-N2 @ 1.25 MPa (0.176 g-mol) 4:1 WAG,10 Slugs,DEAD OIL]

Porosity [%] = 38.6
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 6.26

Pore Volume [cm3] = 1880.0
Initial Oil Saturation [%] = 87.0
Hydrocarbon Pore Volume [cm3] = 1636.4
Carbon Dioxide Retention [%inj] = 67.13

Connate Water Saturation [%] = 11.2
Molar Density @ atm. [kmol/m3] = 0.04160
Absolute Permeability [darcies] = 12.9600
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.30	1.25	32.7	0.0	0.017	0.000	0.00	1.50	1.50	0.09	0.00	0.00	0.046
1.40	1.25	0.0	130.9	0.070	0.005	2.00	121.70	123.20	7.53	0.02	0.04	0.930
1.40	1.25	32.7	0.0	0.017	0.000	0.00	8.50	131.70	8.05	0.00	0.00	0.260
1.80	1.25	0.0	131.0	0.070	0.002	15.00	109.50	241.20	14.74	0.14	0.02	0.836
1.30	1.25	32.7	0.0	0.017	0.000	2.50	5.50	246.70	15.08	0.45	0.00	0.168
1.50	1.25	0.0	136.6	0.073	0.000	48.50	81.00	327.70	20.03	0.60	0.00	0.593
1.30	1.25	32.7	0.0	0.017	0.000	8.00	4.50	332.20	20.30	1.78	0.00	0.138
1.60	1.25	0.0	130.9	0.070	0.000	76.00	43.00	375.20	22.93	1.77	0.00	0.328
1.25	1.25	32.7	0.0	0.017	0.000	10.00	4.00	379.20	23.17	2.50	0.00	0.122
1.25	1.25	0.0	130.9	0.070	0.000	93.00	28.50	407.70	24.91	3.26	0.00	0.218
1.40	1.25	32.7	0.0	0.017	0.000	4.80	13.20	420.90	25.72	0.36	0.00	0.404
1.40	1.25	0.0	140.9	0.075	0.000	100.00	26.50	447.40	27.34	3.77	0.00	0.188
1.40	1.25	32.7	0.0	0.017	0.000	9.80	2.80	450.20	27.51	3.50	0.00	0.086
1.50	1.25	0.0	130.9	0.070	0.001	101.00	18.50	468.70	28.64	5.46	0.05	0.141
1.40	1.25	32.7	0.0	0.017	0.000	21.90	3.10	471.80	28.83	7.06	0.00	0.095
1.35	1.25	0.0	130.9	0.070	0.001	95.00	18.00	489.80	29.93	5.28	0.06	0.138
1.35	1.25	32.7	0.0	0.017	0.000	28.00	3.50	493.30	30.15	8.00	0.00	0.107

TABLE A41 (CONTINUED)

RESULTS OF RUN 2DT09
[0.20 HCPV CO2-N2 @ 1.25 MPa (0.176 g-mol) 4:1 WAG, 10 Slugs, DEAD OIL]

Porosity [%] = 38.6
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 6.26

Pore Volume [cm3] = 1880.0
Initial Oil Saturation [%] = 87.0
Hydrocarbon Pore Volume [cm3] = 1636.4
Carbon Dioxide Retention [%inj] = 67.13

Connate Water Saturation [%] = 11.2
Molar Density @ atm. [kmol/m3] = 0.04160
Absolute Permeability [darcies] = 12.9600
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.40	1.25	0.0	130.9	0.070	0.008	96.00	15.00	508.30	31.06	6.40	0.53	0.115
1.40	1.25	32.7	0.0	0.017	0.005	39.50	3.00	511.30	31.25	13.17	1.67	0.092
1.40	1.25	0.0	130.9	0.070	0.017	91.00	13.00	524.30	32.04	7.00	1.31	0.099
1.40	1.25	0.0	257.6	0.137	0.040	220.00	31.00	555.30	33.93	7.10	1.29	0.120
1.40	1.25	0.0	255.1	0.136	0.032	215.00	31.00	586.30	35.83	6.94	1.03	0.122
1.40	1.25	0.0	252.5	0.134	0.051	229.00	21.20	607.50	37.12	10.80	2.41	0.084
1.40	1.25	0.0	252.9	0.135	0.097	230.00	22.00	629.50	38.47	10.45	4.41	0.087
1.40	1.25	0.0	255.6	0.136	0.106	233.50	21.50	651.00	39.78	10.86	4.93	0.084
1.40	1.25	0.0	253.6	0.135	0.097	233.00	20.00	671.00	41.00	11.65	4.85	0.079
1.40	1.25	0.0	250.6	0.133	0.086	235.00	15.50	686.50	41.95	15.16	5.55	0.062
1.40	1.25	0.0	253.3	0.135	0.074	238.50	14.50	701.00	42.84	16.45	5.10	0.057
1.40	1.25	0.0	256.2	0.136	0.059	241.00	10.20	711.20	43.46	23.63	5.78	0.040
0.01	0.01	0.0	0.0	0.000	0.866	156.00	41.00	752.20	45.97	3.80	21.12	

TABLE A42

RESULTS OF RUN 2DT10
[0.20 HCPV CO2-N2 @ 1.44 MPa (0.208 g-mol) 4:1 WAG,10 Slugs,DEAD OIL]

Porosity [%] = 38.8
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 7.87

Pore Volume [cm3] = 1890.0
Initial Oil Saturation [%] = 88.6
Hydrocarbon Pore Volume [cm3] = 1674.5
Carbon Dioxide Retention [%inj] = 53.52

Connate Water Saturation [%] = 11.9
Molar Density @ atm. [kmol/m3] = 0.04158
Absolute Permeability [darcies] = 11.4000
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.80	1.44	33.5	0.0	0.018	0.000	0.00	3.50	3.50	0.21	0.00	0.00	0.104
2.20	1.44	0.0	134.0	0.071	0.008	4.00	125.50	129.00	7.70	0.03	0.06	0.937
1.70	1.44	33.5	0.0	0.018	0.000	0.50	12.00	141.00	8.42	0.04	0.00	0.358
1.80	1.44	0.0	134.0	0.071	0.002	16.00	106.00	247.00	14.75	0.15	0.02	0.791
1.60	1.44	33.5	0.0	0.018	0.000	4.00	4.90	251.90	15.04	0.82	0.00	0.146
1.80	1.44	0.0	134.0	0.071	0.000	44.00	80.00	331.90	19.82	0.55	0.00	0.597
1.60	1.44	33.5	0.0	0.018	0.000	16.00	5.50	337.40	20.15	2.91	0.00	0.164
1.60	1.44	0.0	134.0	0.071	0.001	76.50	39.00	376.40	22.48	1.96	0.03	0.291
1.60	1.44	33.5	0.0	0.018	0.000	23.00	5.00	381.40	22.78	4.60	0.00	0.149
1.70	1.44	0.0	134.0	0.071	0.038	93.00	24.00	405.40	24.21	3.88	1.58	0.179
1.60	1.44	33.5	0.0	0.018	0.006	22.70	4.30	409.70	24.47	5.28	1.40	0.128
1.70	1.44	0.0	134.0	0.071	0.070	97.00	20.00	429.70	25.66	4.85	3.50	0.149
1.70	1.44	33.5	0.0	0.018	0.008	23.50	4.50	434.20	25.93	5.22	1.78	0.134
1.60	1.44	0.0	134.4	0.071	0.109	92.00	22.00	456.20	27.24	4.18	4.95	0.164
1.60	1.44	33.5	0.0	0.018	0.018	23.00	4.00	460.20	27.48	5.75	4.50	0.119
1.60	1.44	0.0	134.0	0.071	0.169	92.00	24.00	484.20	28.92	3.83	7.04	0.179
1.60	1.44	33.5	0.0	0.018	0.018	23.70	3.80	488.00	29.14	6.24	4.74	0.113

TABLE A42 (CONTINUED)

RESULTS OF RUN 2DT10
[0.20 HCPV CO2-N2 @ 1.44 MPa (0.208 g-mol) 4:1 WAG,10 Slugs,DEAD OIL]

Porosity [%] = 38.8
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 7.87

Pore Volume [cm3] = 1890.0
Initial Oil Saturation [%] = 88.6
Hydrocarbon Pore Volume [cm3] = 1674.5
Carbon Dioxide Retention [%inj] = 53.52

Connate Water Saturation [%] = 11.9
Molar Density @ atm. [kmol/m3] = 0.04158
Absolute Permeability [darcies] = 11.4000
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.60	1.44	0.0	134.0	0.071	0.174	95.00	22.00	510.00	30.46	4.32	7.91	0.164
1.60	1.44	33.5	0.0	0.018	0.028	24.30	3.20	513.20	30.65	7.59	8.75	0.095
1.60	1.44	0.0	134.0	0.071	0.294	92.00	18.00	531.20	31.72	5.11	16.33	0.134
1.60	1.44	0.0	257.8	0.136	0.326	223.00	29.00	560.20	33.45	7.69	11.24	0.112
1.60	1.44	0.0	259.2	0.137	0.306	223.00	29.00	589.20	35.19	7.69	10.55	0.112
1.60	1.44	0.0	253.1	0.134	0.230	225.00	26.00	615.20	36.74	8.65	8.85	0.103
1.60	1.44	0.0	255.4	0.135	0.163	227.50	24.50	639.70	38.20	9.29	6.65	0.096
1.60	1.44	0.0	256.0	0.135	0.123	231.00	19.00	658.70	39.34	12.16	6.47	0.074
1.60	1.44	0.0	252.3	0.133	0.097	233.00	18.00	676.70	40.41	12.94	5.39	0.071
1.60	1.44	0.0	250.6	0.133	0.094	235.00	16.00	692.70	41.37	14.69	5.87	0.064
1.60	1.44	0.0	253.3	0.134	0.099	238.00	14.00	706.70	42.20	17.00	7.07	0.055
1.60	1.44	0.0	256.2	0.136	0.063	240.00	10.00	716.70	42.80	24.00	6.30	0.039
0.01	0.01	0.0	0.0	0.000	0.334	159.00	43.00	759.70	45.37	3.70	7.77	

TABLE A44

RESULTS OF RUN 2DT12
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.150 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 40.6
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.18

Pore Volume [cm3] = 1977.0
Initial Oil Saturation [%] = 89.5
Hydrocarbon Pore Volume [cm3] = 1756.0
Carbon Dioxide Retention [%inj] = 16.37

Connate Water Saturation [%] = 10.5
Molar Density @ atm. [kmol/m3] = 0.04162
Absolute Permeability [darcies] = 11.8300
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	35.1	0.0	0.018	0.002	0.00	5.50	5.50	0.31	0.00	0.36	0.157
1.30	1.00	0.0	140.4	0.071	0.021	0.00	131.00	136.50	7.77	0.00	0.16	0.933
1.30	1.00	35.1	0.0	0.018	0.003	0.00	13.00	149.50	8.51	0.00	0.23	0.370
1.20	1.00	0.0	140.5	0.071	0.014	5.50	124.50	274.00	15.60	0.04	0.11	0.886
1.20	1.00	35.1	0.0	0.018	0.044	4.00	10.60	284.60	16.21	0.38	4.15	0.302
1.40	1.00	0.0	140.5	0.071	0.028	33.50	96.00	380.60	21.67	0.35	0.29	0.683
1.20	1.00	35.1	0.0	0.018	0.018	14.00	9.60	390.20	22.22	1.46	1.87	0.274
1.30	1.00	0.0	140.5	0.071	0.054	61.00	54.00	444.20	25.30	1.13	1.00	0.384
1.20	1.00	35.1	0.0	0.018	0.005	29.00	8.50	452.70	25.78	3.41	0.59	0.242
1.20	1.00	0.0	144.5	0.073	0.121	66.00	42.00	494.70	28.17	1.57	2.88	0.291
1.20	1.00	35.1	0.0	0.018	0.022	27.00	7.00	501.70	28.57	3.86	3.14	0.199
1.20	1.00	0.0	140.5	0.071	0.147	77.00	35.80	537.50	30.61	2.15	4.11	0.255
1.20	1.00	35.1	0.0	0.018	0.049	29.00	3.40	540.90	30.80	8.53	14.41	0.097
1.10	1.00	0.0	140.5	0.071	0.181	79.00	27.00	567.90	32.34	2.93	6.70	0.192
1.10	1.00	35.1	0.0	0.018	0.058	27.20	3.80	571.70	32.56	7.16	15.26	0.108
1.10	1.00	0.0	140.5	0.071	0.128	84.00	25.50	597.20	34.01	3.29	5.02	0.182
1.10	1.00	35.1	0.0	0.018	0.034	27.20	3.80	601.00	34.23	7.16	8.95	0.108

TABLE A44 (CONTINUED)

RESULTS OF RUN 2DT12
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.150 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 40.6
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.18

Pore Volume [cm3] = 1977.0
Initial Oil Saturation [%] = 89.5
Hydrocarbon Pore Volume [cm3] = 1756.0
Carbon Dioxide Retention [%inj] = 16.37

Connate Water Saturation [%] = 10.5
Molar Density @ atm. [kmol/m3] = 0.04162
Absolute Permeability [darcies] = 11.8300
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	140.5	0.071	0.259	92.00	15.20	616.20	35.09	6.05	17.04	0.108
1.10	1.00	35.1	0.0	0.018	0.047	30.50	4.10	620.30	35.32	7.44	11.46	0.117
1.10	1.00	0.0	140.5	0.071	0.293	86.50	20.50	640.80	36.49	4.22	14.29	0.146
1.10	1.00	0.0	253.9	0.128	0.192	214.00	40.00	680.80	38.77	5.35	4.80	0.158
1.10	1.00	0.0	257.1	0.130	0.612	225.00	25.00	705.80	40.19	9.00	24.48	0.097
1.10	1.00	0.0	250.2	0.127	0.150	226.00	24.00	729.80	41.56	9.42	6.25	0.096
1.10	1.00	0.0	251.2	0.127	0.127	232.00	20.00	749.80	42.70	11.60	6.35	0.080
1.10	1.00	0.0	251.5	0.127	0.154	236.00	15.00	764.80	43.55	15.73	10.27	0.060
1.10	1.00	0.0	252.4	0.128	0.058	237.00	15.00	779.80	44.41	15.80	3.87	0.059
0.01	0.01	0.0	0.0	0.000	0.794	159.00	54.20	834.00	47.49	2.93	14.65	

TABLE A45

RESULTS OF RUN 2DT13

[0.20 HCPV CO2-N2 @ 1.0 MPa (0.148 g-mol) 4:1 WAG, 10 Slugs, DEAD OIL]

Porosity [%] = 39.3
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.29

Pore Volume [cm3] = 1915.0
Initial Oil Saturation [%] = 90.5
Hydrocarbon Pore Volume [cm3] = 1733.0
Carbon Dioxide Retention [%inj] = 18.56

Connate Water Saturation [%] = 9.5
Molar Density @ atm. [kmol/m3] = 0.04160
Absolute Permeability [darcies] = 11.8600
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	34.6	0.0	0.018	0.001	0.00	2.00	2.00	0.12	0.00	0.50	0.058
1.20	1.00	0.0	138.6	0.072	0.012	1.00	124.50	126.50	7.30	0.01	0.10	0.898
1.20	1.00	34.6	0.0	0.018	0.000	0.00	19.00	145.50	8.40	0.00	0.00	0.549
1.30	1.00	0.0	138.6	0.072	0.015	10.00	118.80	264.30	15.25	0.08	0.13	0.857
1.30	1.00	34.6	0.0	0.018	0.000	9.80	20.20	284.50	16.42	0.49	0.00	0.583
1.40	1.00	0.0	138.7	0.072	0.000	34.20	78.80	363.30	20.96	0.43	0.00	0.568
1.20	1.00	34.6	0.0	0.018	0.001	19.00	15.00	378.30	21.83	1.27	0.07	0.433
1.20	1.00	0.0	138.6	0.072	0.005	55.00	53.00	431.30	24.89	1.04	0.09	0.382
1.20	1.00	34.6	0.0	0.018	0.001	24.50	10.50	441.80	25.49	2.33	0.10	0.303
1.20	1.00	0.0	138.6	0.072	0.035	64.00	49.00	490.80	28.32	1.31	0.71	0.353
1.20	1.00	34.6	0.0	0.018	0.006	28.70	8.70	499.50	28.82	3.30	0.69	0.251
1.10	1.00	0.0	138.6	0.072	0.072	76.00	36.50	536.00	30.93	2.08	1.97	0.263
1.10	1.00	34.6	0.0	0.018	0.003	29.60	6.90	542.90	31.33	4.29	0.43	0.199
1.10	1.00	0.0	138.7	0.072	0.182	70.00	33.00	575.90	33.23	2.12	5.52	0.238
1.10	1.00	34.6	0.0	0.018	0.004	23.30	5.20	581.10	33.53	4.48	0.77	0.150
1.10	1.00	0.0	138.6	0.072	0.111	86.00	29.00	610.10	35.20	2.97	3.83	0.209
1.10	1.00	34.6	0.0	0.018	0.012	32.10	5.70	615.80	35.53	5.63	2.11	0.165

TABLE A45 (CONTINUED)

RESULTS OF RUN 2DT13
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.148 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 39.3
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 5.29

Pore Volume [cm3] = 1915.0
Initial Oil Saturation [%] = 90.5
Hydrocarbon Pore Volume [cm3] = 1733.0
Carbon Dioxide Retention [%inj] = 18.56

Connate Water Saturation [%] = 9.5
Molar Density @ atm. [kmol/m3] = 0.04160
Absolute Permeability [darcies] = 11.8600
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	138.7	0.072	0.171	92.00	15.20	631.00	36.41	6.05	11.25	0.110
1.10	1.00	34.6	0.0	0.018	0.024	29.50	5.00	636.00	36.70	5.90	4.80	0.144
1.10	1.00	0.0	139.1	0.073	0.252	90.00	17.00	653.00	37.68	5.29	14.82	0.122
1.10	1.00	0.0	256.6	0.134	0.243	225.00	26.00	679.00	39.18	8.65	9.35	0.101
1.10	1.00	0.0	255.0	0.133	0.341	228.00	24.00	703.00	40.57	9.50	14.21	0.094
1.10	1.00	0.0	258.4	0.135	0.327	233.00	18.00	721.00	41.60	12.94	18.17	0.070
1.10	1.00	0.0	253.9	0.133	0.241	239.50	14.40	735.40	42.44	16.63	16.74	0.057
0.01	0.01	0.0	0.0	0.000	1.384	167.00	64.00	799.40	46.13	2.61	21.62	

TABLE A46

RESULTS OF RUN 2DT14
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.149 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 40.2
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.93

Pore Volume [cm3] = 1958.0
Initial Oil Saturation [%] = 89.4
Hydrocarbon Pore Volume [cm3] = 1751.5
Carbon Dioxide Retention [%inj] = 38.54

Connate Water Saturation [%] = 10.6
Molar Density @ atm. [kmol/m3] = 0.04159
Absolute Permeability [darcies] = 11.4300
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	35.0	0.0	0.018	0.000	0.00	3.50	3.50	0.20	0.00	0.00	0.100
1.50	1.00	0.0	140.1	0.072	0.009	0.00	126.00	129.50	7.39	0.00	0.07	0.899
1.20	1.00	35.0	0.0	0.018	0.001	0.00	15.00	144.50	8.25	0.00	0.07	0.428
1.30	1.00	0.0	140.1	0.072	0.007	2.00	122.00	266.50	15.22	0.02	0.06	0.871
1.30	1.00	35.0	0.0	0.018	0.000	5.30	19.70	286.20	16.34	0.27	0.00	0.562
1.10	1.00	0.0	140.1	0.072	0.004	22.00	95.50	381.70	21.79	0.23	0.04	0.681
1.20	1.00	35.0	0.0	0.018	0.000	11.60	12.60	394.30	22.51	0.92	0.00	0.360
1.20	1.00	0.0	140.3	0.072	0.003	59.80	54.20	448.50	25.61	1.10	0.06	0.386
1.20	1.00	35.0	0.0	0.018	0.001	18.90	9.10	457.60	26.13	2.08	0.11	0.260
1.10	1.00	0.0	140.1	0.072	0.001	86.20	31.20	488.80	27.91	2.76	0.03	0.223
1.20	1.00	35.0	0.0	0.018	0.000	24.50	6.00	494.80	28.25	4.08	0.00	0.171
1.10	1.00	0.0	140.1	0.072	0.002	93.00	23.50	518.30	29.59	3.96	0.09	0.168
1.10	1.00	35.0	0.0	0.018	0.000	37.50	5.50	523.80	29.91	6.82	0.00	0.157
1.10	1.00	0.0	140.1	0.072	0.026	82.00	26.50	550.30	31.42	3.09	0.98	0.189
1.10	1.00	35.0	0.0	0.018	0.003	29.00	4.00	554.30	31.65	7.25	0.75	0.114
1.10	1.00	0.0	140.1	0.072	0.042	87.00	18.00	572.30	32.67	4.83	2.33	0.128
1.10	1.00	35.0	0.0	0.018	0.007	32.00	6.00	578.30	33.02	5.33	1.17	0.171

TABLE A46 (CONTINUED)

RESULTS OF RUN 2DT14
[0.20 HCPV CO2-N2 @ 1.0 MPa (0.149 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]

Porosity [%] = 40.2
Oil Viscosity [mPa.s] = 1058.0
Average Run Temperature [K] = 294.15
Carbon Dioxide Required [sm3/sm3] = 4.93

Pore Volume [cm3] = 1958.0
Initial Oil Saturation [%] = 89.4
Hydrocarbon Pore Volume [cm3] = 1751.5
Carbon Dioxide Retention [%inj] = 38.54

Connate Water Saturation [%] = 10.6
Molar Density @ atm. [kmol/m3] = 0.04159
Absolute Permeability [darcies] = 11.4300
Average Flow Velocity [m/d] = 2.600

PRESS inj (MPa)	PRESS prod (MPa)	GAS inj (cm3)	WATER inj (cm3)	VFI/PV -- (cm3/cm3)	GAS prod (s.ltr)	WATER prod (cm3)	OIL prod (cm3)	CUM OIL prod (cm3)	PERCENT Recovery (%)	WOR -- (sm3/sm3)	GOR -- (sm3/sm3)	OPFIR -- (sm3/m3)
1.10	1.00	0.0	140.1	0.072	0.127	89.70	16.00	594.30	33.93	5.61	7.94	0.114
1.10	1.00	35.0	0.0	0.018	0.007	26.00	5.00	599.30	34.22	5.20	1.40	0.143
1.10	1.00	0.0	140.1	0.072	0.119	85.00	15.00	614.30	35.07	5.67	7.93	0.107
1.10	1.00	0.0	265.8	0.136	0.066	214.00	37.00	651.30	37.19	5.78	1.78	0.139
1.10	1.00	0.0	252.8	0.129	0.087	217.00	33.50	684.80	39.10	6.48	2.60	0.133
1.10	1.00	0.0	250.2	0.128	0.120	216.00	33.00	717.80	40.98	6.55	3.64	0.132
1.10	1.00	0.0	249.2	0.127	0.135	213.00	36.00	753.80	43.04	5.92	3.75	0.144
1.10	1.00	0.0	249.5	0.127	0.124	227.50	24.50	778.30	44.44	9.29	5.06	0.098
1.10	1.00	0.0	253.1	0.129	0.106	231.00	19.50	797.80	45.55	11.85	5.44	0.077
0.01	0.01	0.0	0.0	0.000	1.633	177.00	71.00	868.80	49.60	2.49	23.00	

APPENDIX B

Sample Calculation of Carbon Dioxide-Saturated Oil Viscosity

The correlation of oil viscosity with concentration of carbon dioxide or methane or ethane at any pressure and temperature is as below[95]:

$$\ln \mu_{T,p,x} = 2.3026\left[\frac{b}{\left(1 + \frac{T - 30}{303.15}\right)^{s}} - 3.0020\right] + B_o * p * \exp(d * T) - C_o * x * \exp(-E * T)$$

Where:

μ = Viscosity of oil, Pa.s
T = Temperature, °C
p = Pressure, MPag
$b = \log \mu_{(30\,°C,\,0\,MPag)} + 3.0020$
$s = 0.0066940*b + 3.5364$
$B_o = 0.0047424*b + 0.0081709$
$d = -0.0015646*b + 0.0061814$
$$x = \frac{\text{moles additive}}{\text{moles oil} + \text{moles additive}} \times 100$$

For Carbon Dioxide,
$C_o = 0.021519*b + 0.020952$
$E = 0.0015469*b + 0.0036339$

For Methane,
$C_o = 0.031396*b - 0.031399$
$E = 0.0024696*b - 0.0017938$

For Ethane,
$C_o = 0.026779*b + 0.0024410$
$E = 0.0024564*b - 0.0018401$

The procedure to estimate the viscosity of carbon dioxide-saturated oil, as suggested by Singh et al.[95], is as shown on the next page.

Data:
x = 19.1239%
$\mu_{21°C,\,1\,atm}$ = 1058.0 mPa.s
Step 1: obtain b by trial and error.
Trial no.1: assume $\mu_{30\,°C}$ = 500.0 mPa.s or 0.500 Pa.s

$$b = \log \mu_{(30\,^{\circ}\mathrm{C},\ 0\ \mathrm{MPag})} + 3.0020$$

$$= \log(0.500) + 3.002 = 2.70097$$

$$s = 0.0066940{*}b + 3.5364 = 3.55448$$

$$\ln \mu_{21^{\circ}\mathrm{C},\ 0\ \mathrm{MPag}} = 2.3026\left[\frac{b}{\left(1 + \dfrac{T - 30}{303.15}\right)^{s}} - 3.0020\right]$$

$$= 2.3026\left[\frac{2.70097}{\left(1 + \dfrac{21 - 30}{303.15}\right)^{3.55448}} - 3.0020\right]$$

$$= 0.0100753$$

$$\mu_{21\,^{\circ}\mathrm{C},\ 0\ \mathrm{MPag}} = 1.0101\ \mathrm{Pa.s} = 1010.1\ \mathrm{mPa.s}$$

Trial no.2: assume $\mu_{30\,^{\circ}\mathrm{C}}$ = 510.0 mPa.s = 0.510 mPa.s

$$b = 2.70957$$

$$s = 3.55454$$

$$\mu_{21\,^{\circ}\mathrm{C},\ 0\ \mathrm{MPag}} = 1.0327\ \mathrm{Pa.s} = 1032.7\ \mathrm{mPa.s}$$

The same trial was to be carried out until the calculated $\mu_{(21\,^{\circ}\mathrm{C},\ 0\ \mathrm{MPag})}$ matched the experimental measurement, i.e, 1058.0 mPa.s. The b and s values at this trial were used to compute B_o, d, C_o, and E.

$b = 2.71909$

$s = 3.55460$

$B_o = 0.0047427{*}2.71909 + 0.0081709 = 0.0210667$

$d = -0.0015646{*}2.71909 + 0.0061814 = 0.0019271$

$C_o = 0.021519{*}2.71909 + 0.020952 = 0.079464$

$E = 0.0015469{*}2.71909 + 0.0036339 = 0.007840$

By replacing these values in the correlation, the viscosity of carbon dioxide-saturated oil at 1.0 MPag and 21°C was estimated to be 298.05 mPa.s.

APPENDIX C

Sample Calculation of Molecular Diffusion Coefficient of Carbon Dioxide

DATA:

Diffusing Gas: Pure Carbon Dioxide at 1.0 MPag and 23°C

Δt = diffusion time = 1740600 s (483.5 hrs)

m_o = mass of oil = 65.94 g

V_{CO_2} = volume of carbon dioxide collected = 554 cm^3

A = internal cross sectional area of the diffusion cell = 32.17 cm^2

ΔL = length of the oil column = 52 cm

MW_o = molecular weight of oil = 424 g/g-mole

MW_g = molecular weight of carbon dioxide = 44.01 g/g-mole

ρ_g = density of carbon dioxide = 0.01908 g/cm^3

ρ_o = density of oil = 0.9324 g/cm^3

CALCULATIONS:

Since 1 mole of gas occupies 22414 cm^3, the number of mole of CO_2 in the CO_2-oil mixture:

$$n_{CO_2} = \frac{V_{CO_2}}{V_o} = \frac{554\ cm^3}{22414\ cm^3 / g\text{-}mole} = 0.02472 \text{ moles}$$

Moles of oil in the CO_2-oil mixture:

$$n_o = \frac{m_o}{MW_o} = \frac{65.94\ g}{424\ g / g\text{-}mole} = 0.1555 \text{ moles}$$

The molar fraction of CO_2 in the CO_2-oil mixture:

$$x_{CO_2} = \frac{n_{CO_2}}{n_{CO_2} + n_o} = \frac{0.02472 \text{ moles}}{0.02472 \text{ moles} + 0.1555 \text{ moles}} = 0.1371$$

and the corresponding molar fraction of oil:

$$x_o = 1 - x_{CO_2} = 0.8629$$

The specific volume of the CO_2-oil mixture at 1.0 MPag and 23°C:

$$\upsilon_f = \upsilon_o x_o + \upsilon_{CO_2} x_{CO_2} = \frac{1}{\rho_o} x_o + \frac{1}{\rho_{CO_2}} x_{CO_2}$$

$$= \frac{1}{0.9324\ \mathrm{g/cm^3}} 0.8629 + \frac{1}{0.01908\ \mathrm{g/cm^3}} 0.1371 = 8.111\ \mathrm{cm^3/g}$$

The concentration gradient of CO_2 in the CO_2-oil mixture:

$$\frac{\Delta C}{\Delta L} = \frac{1}{\Delta L}(C_2 - C_1)$$

Where C_1 and C_2 are respectively the concentration of CO_2 at the CO_2-oil contact and in the oil sample and defined as follows:

$$C_1 = \frac{1}{\upsilon_{CO_2} MW_{CO_2}}$$

$$C_2 = \frac{m_{CO_2} / MW_{CO_2}}{m_f \upsilon_f} = \frac{m_{CO_2}}{m_f \upsilon_f MW_{CO_2}}$$

where

m_f = mass of oil + mass of CO_2

Substituting into the $\Delta C/\Delta L$ expression yields

$$\frac{\Delta C}{\Delta L} = \frac{1}{\Delta L}\left(\frac{m_{CO_2}}{m_f \upsilon_f MW_{CO_2}} - \frac{1}{\upsilon_{CO_2} MW_{CO_2}}\right)$$

Substituting numerical values to obtain the CO_2 concentration gradient

$$\frac{\Delta C}{\Delta L} = -7.4643\mathrm{E}-06\ \mathrm{g\text{-}mole/cm^3\text{-}cm}$$

(Negative sign means that the concentration of CO_2 decreases with distance)

The molar flux of CO_2 into oil is calculated as follows:

$$\frac{\Delta G}{\Delta t} = \frac{m_{CO_2} / MW_{CO_2}}{\Delta t} = 1.4201\mathrm{E}-08\ \mathrm{g\text{-}mole/s}$$

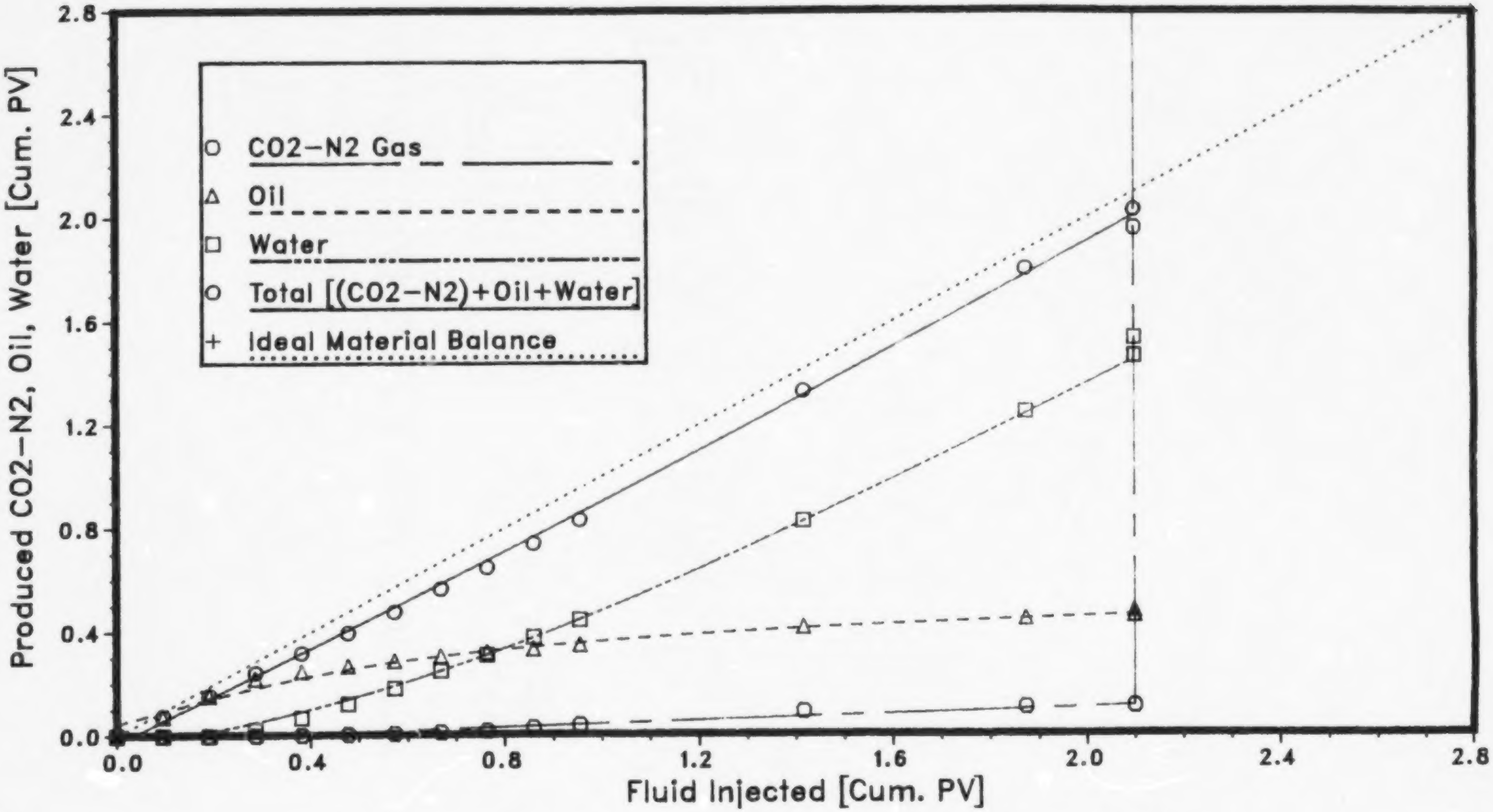
Finally, the molecular diffusion coefficient of CO_2 is estimated using Fick's law of diffusion.

$$D_o = -\frac{1}{A\frac{\Delta C}{\Delta L}}\frac{\Delta G}{\Delta t}$$

$$= 5.9162E\text{-}05\ cm^2/s.$$

APPENDIX D

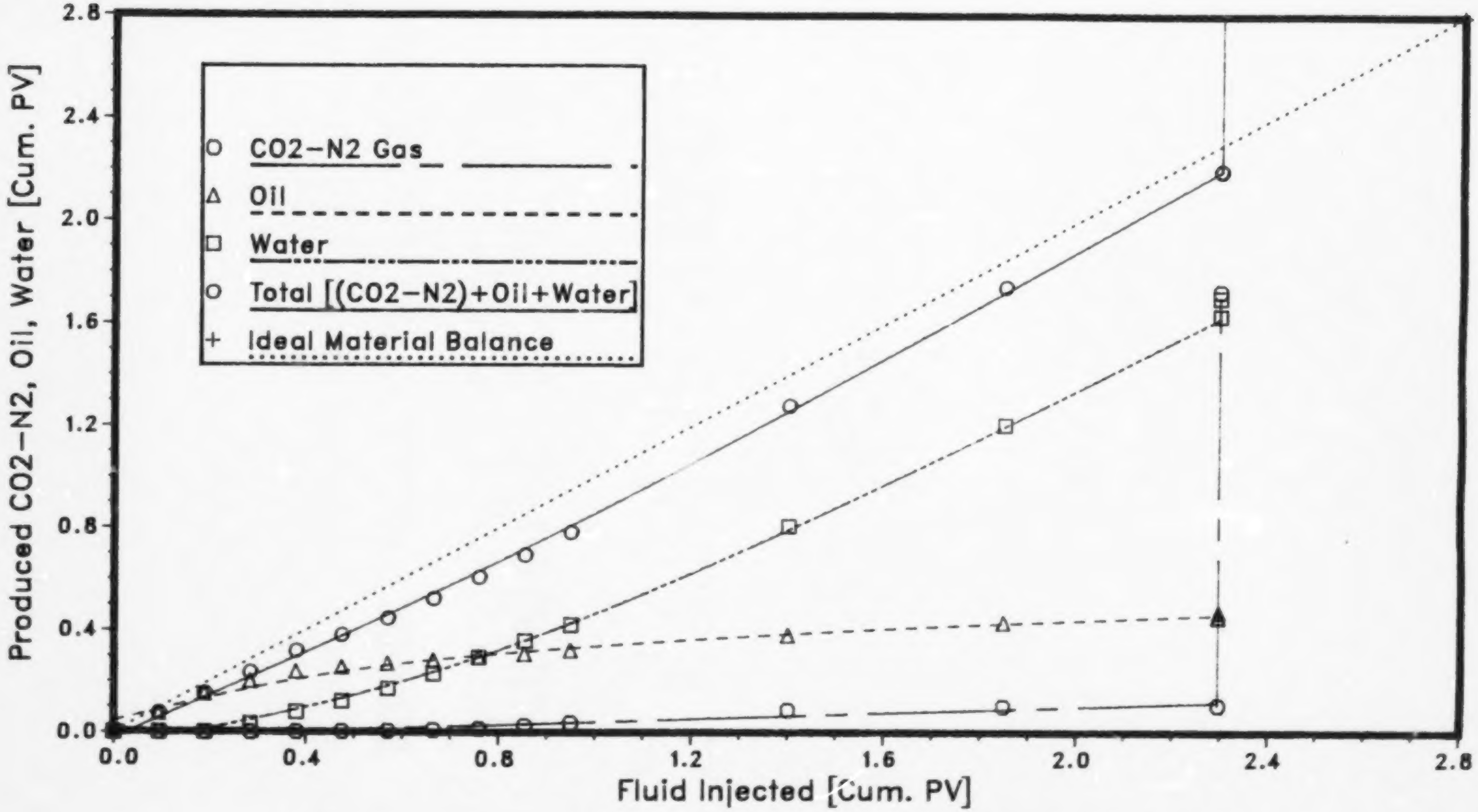
Volumetric Balance Plots of All Experiments Conducted



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1058.0 mPa.s
ϕ = 35.73 %, k = 11.310 darcies, S_o = 94.98 %, S_{wc} = 5.02 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.092 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 4.98%

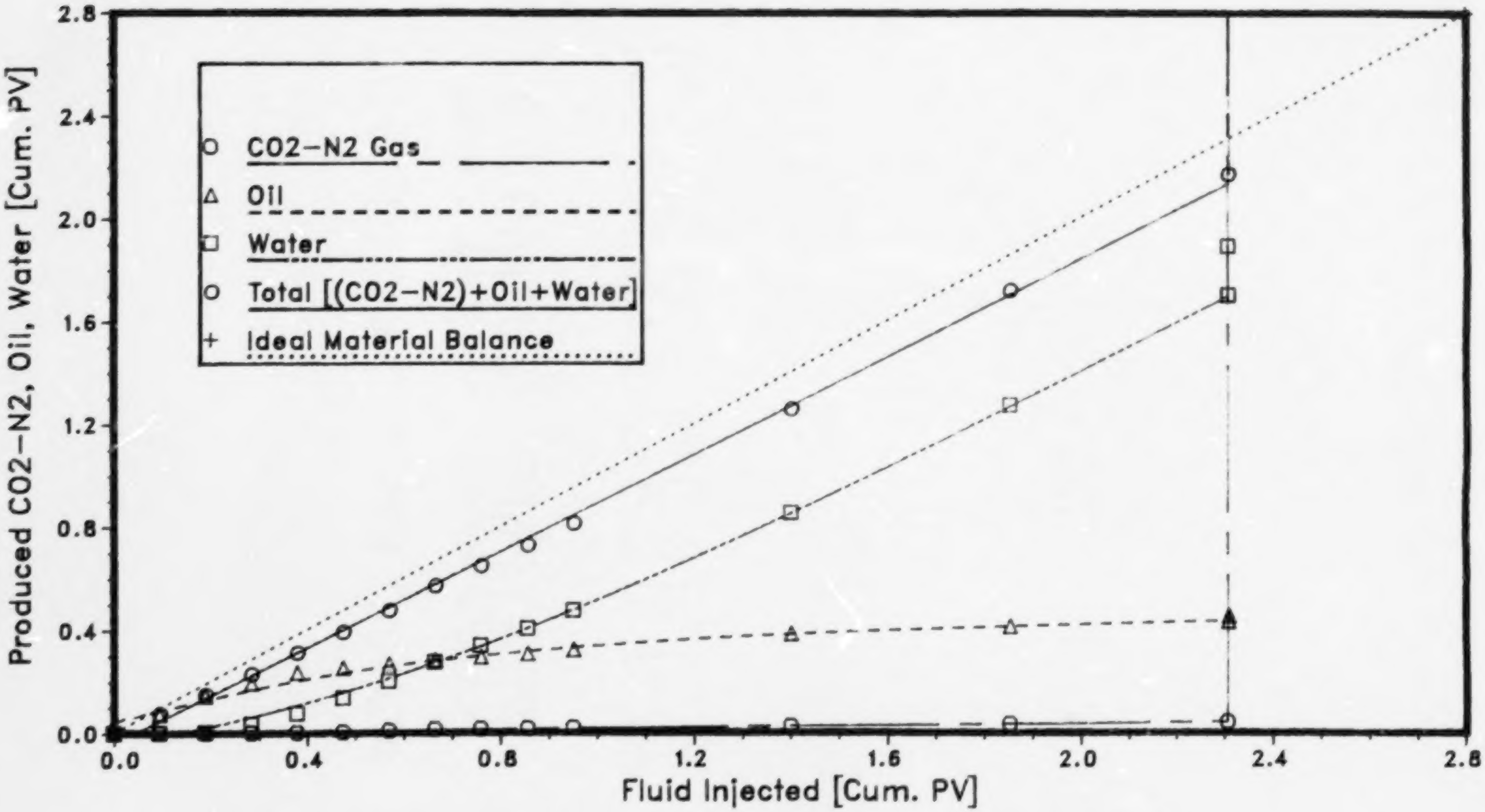
Figure D1 – Volumetric Balance on Run 1DT1.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1058.0 mPa.s
ϕ = 35.82 %, k = 10.700 darcies, S_o = 94.86 %, S_{wc} = 5.14 %

[0.20 HCPV CO2−N2 @ 1.0 MPa (0.091 g−mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 9.99%

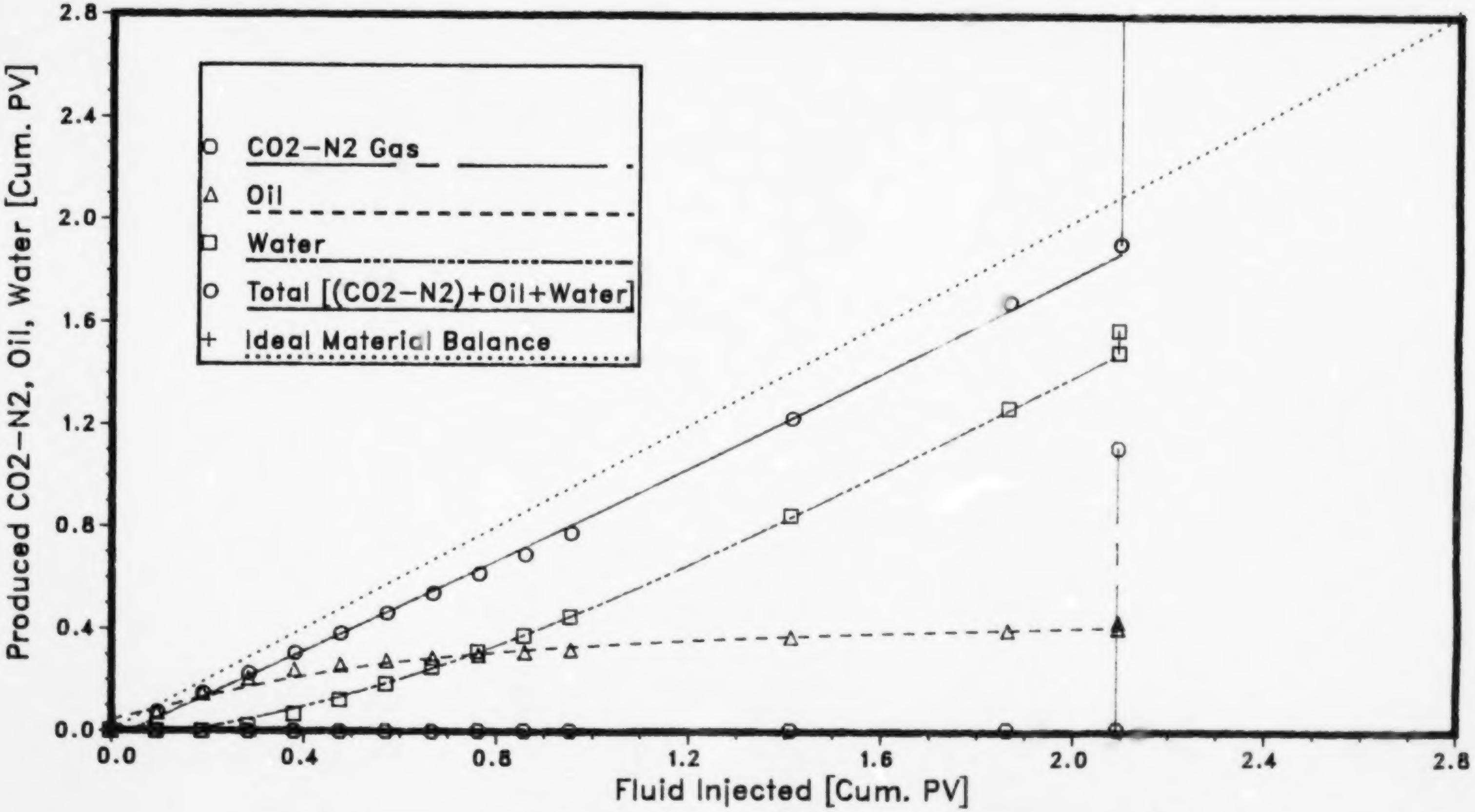
Figure D2 — Volumetric Balance on Run 1DT2.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1058.0 mPa.s
ϕ = 36.06 %, k = 10.510 darcies, S_o = 92.44 %, S_{wc} = 7.56 %

[0.20 HCPV CO2−N2 @ 1.0 MPa (0.091 g−mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.00%

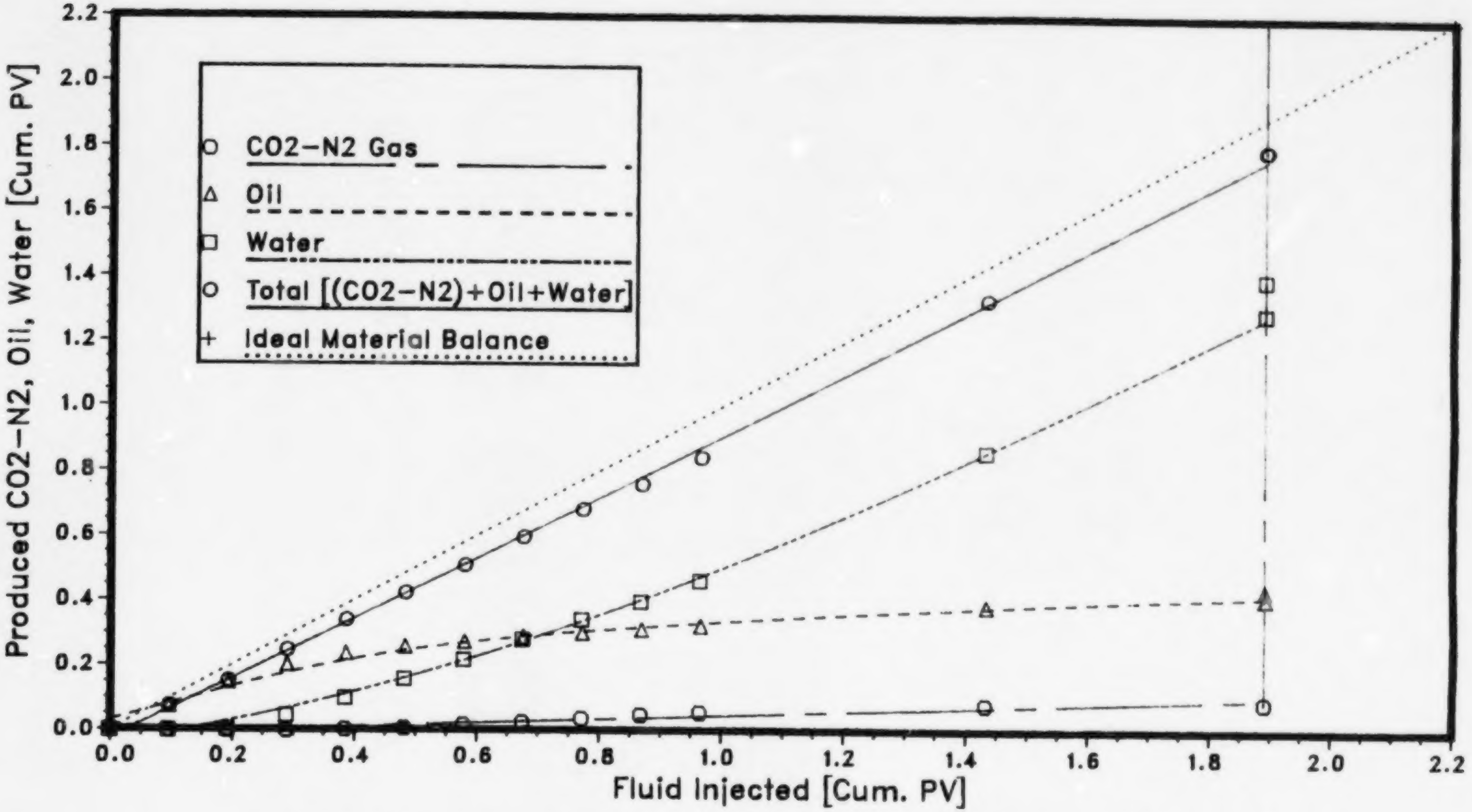
Figure D3 – Volumetric Balance on Run 1DT3.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1058.0 mPa.s
ϕ = 35.59 %, k = 10.770 darcies, S_o = 95.53 %, S_{wc} = 4.47 %

[0.20 HCPV CO2−N2 @ 1.0 MPa (0.090 g−mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 20.00%

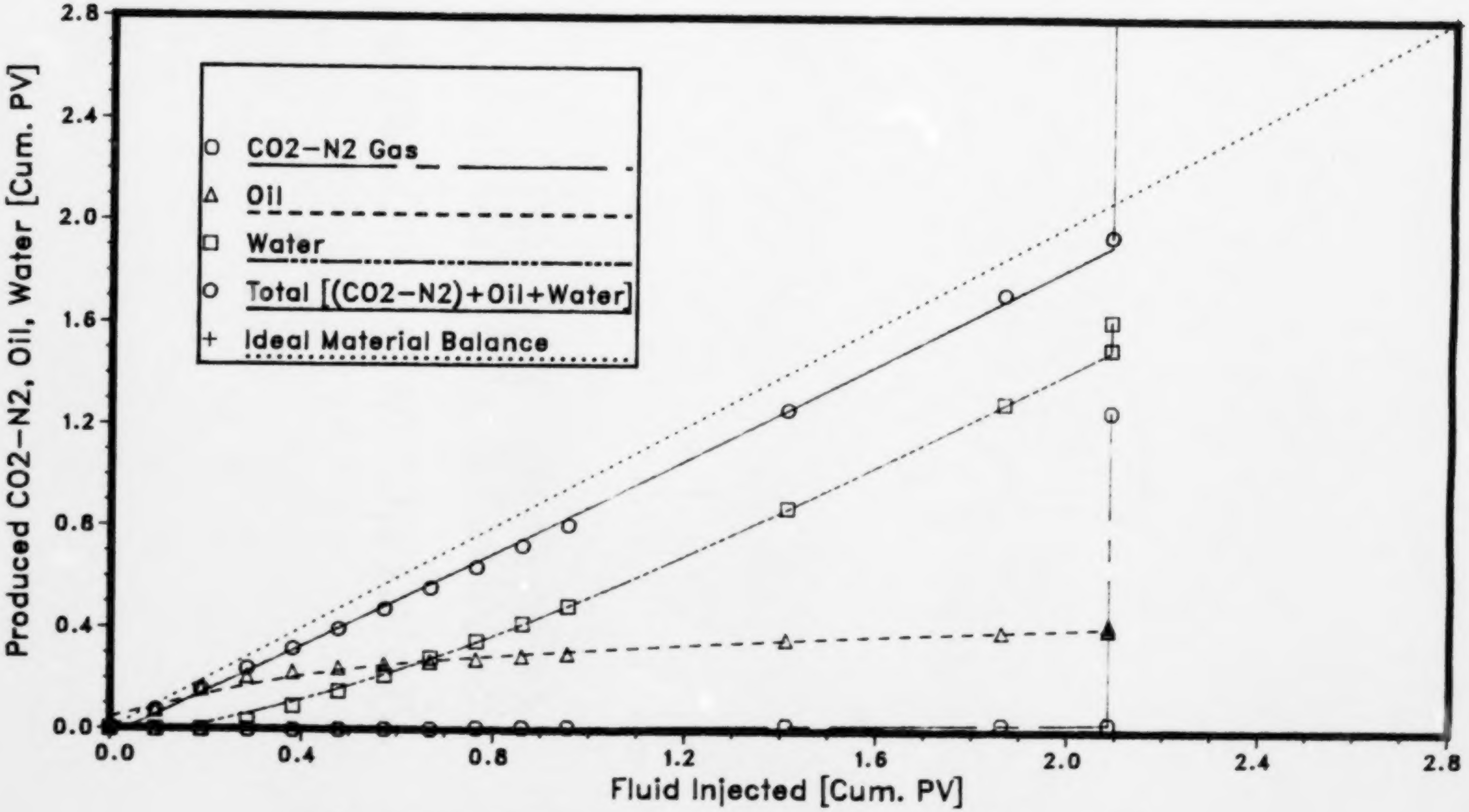
Figure D4 — Volumetric Balance on Run 1DT4.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1058.0 mPa.s
ϕ = 35.16 %, k = 10.630 darcies, S_o = 95.28 %, S_{wc} = 4.72 %

[0.20 HCPV CO2−N2 @ 1.0 MPa (0.090 g−mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 25.00%

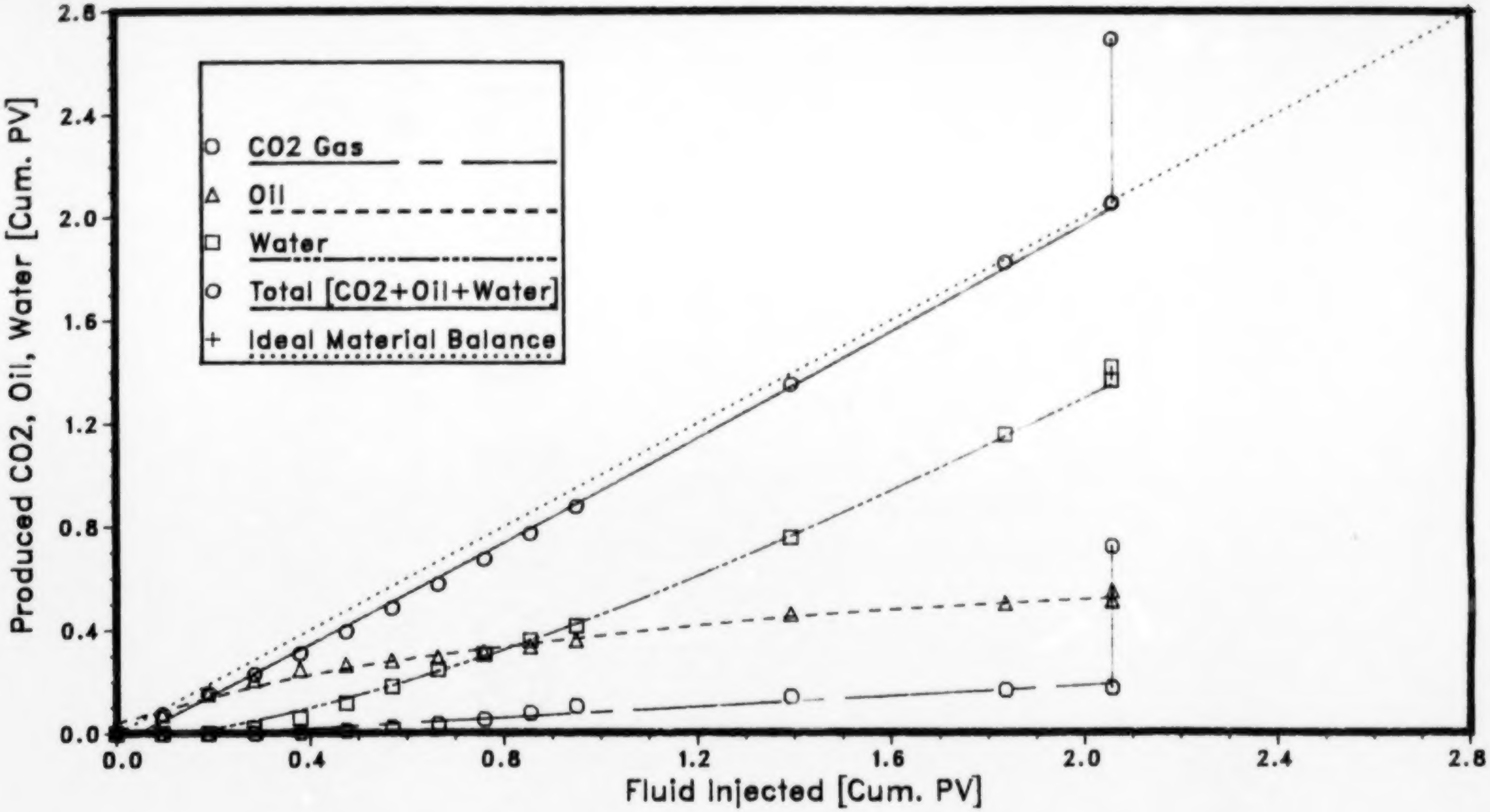
Figure D5 — Volumetric Balance on Run 1DT5.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1058.0 mPa.s
ϕ = 35.70 %, k = 10.730 darcies, S_o = 95.54 %, S_{wc} = 4.46 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.090 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 30.00%

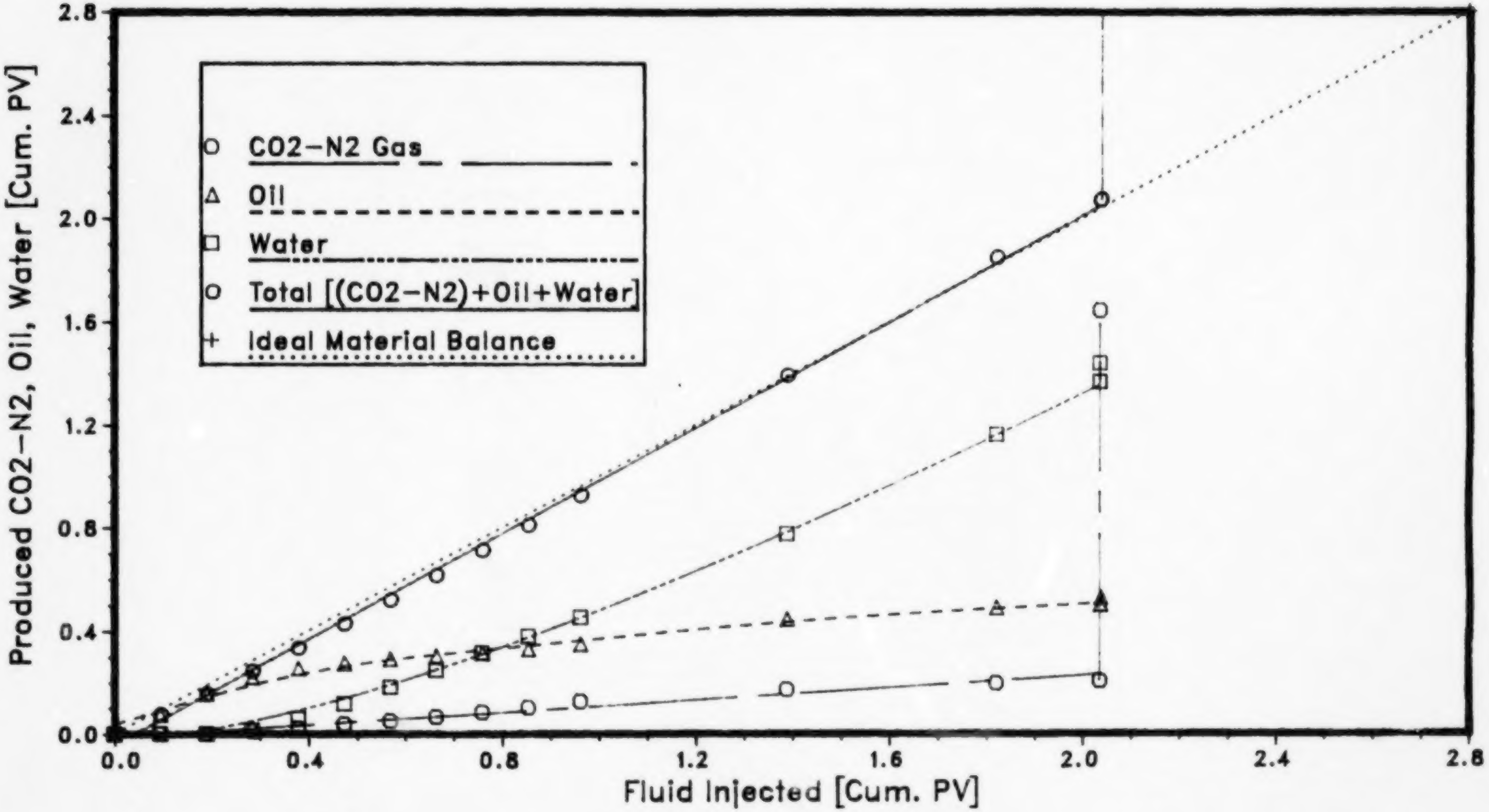
Figure D6 – Volumetric Balance on Run 1DT6.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.83 %, k = 11.040 darcies, S_o = 94.98 %, S_{wc} = 5.02 %

[0.20 HCPV CO2 @ 1.0 MPa (0.092 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]

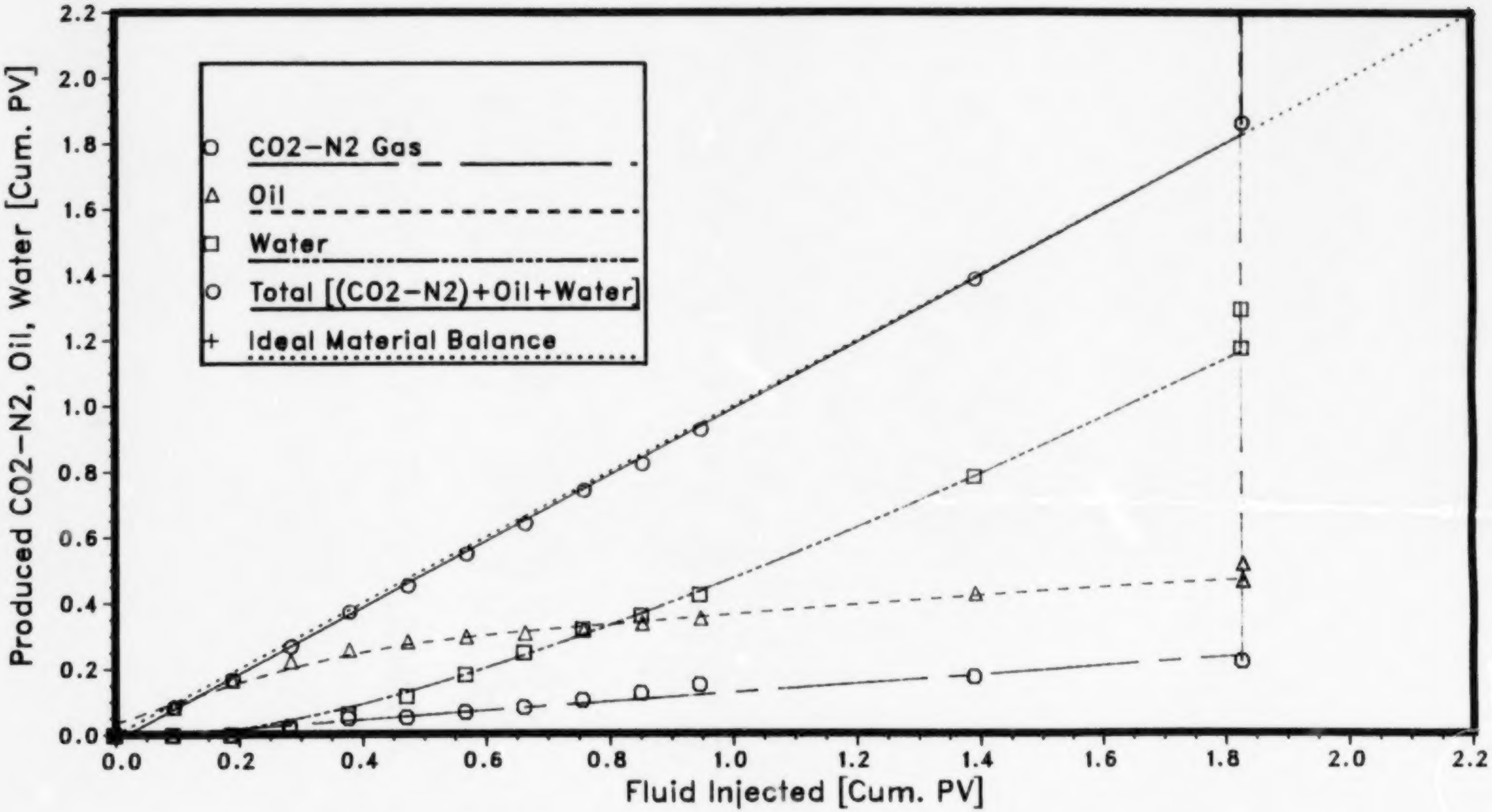
Figure D7 – Volumetric Balance on Run 1DT7.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 36.43 %, k = 11.180 darcies, S_o = 94.99 %, S_{wc} = 5.01 %

[0.20 HCPV CO2–N2 @ 1.00 MPa (0.092 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 4.98%.

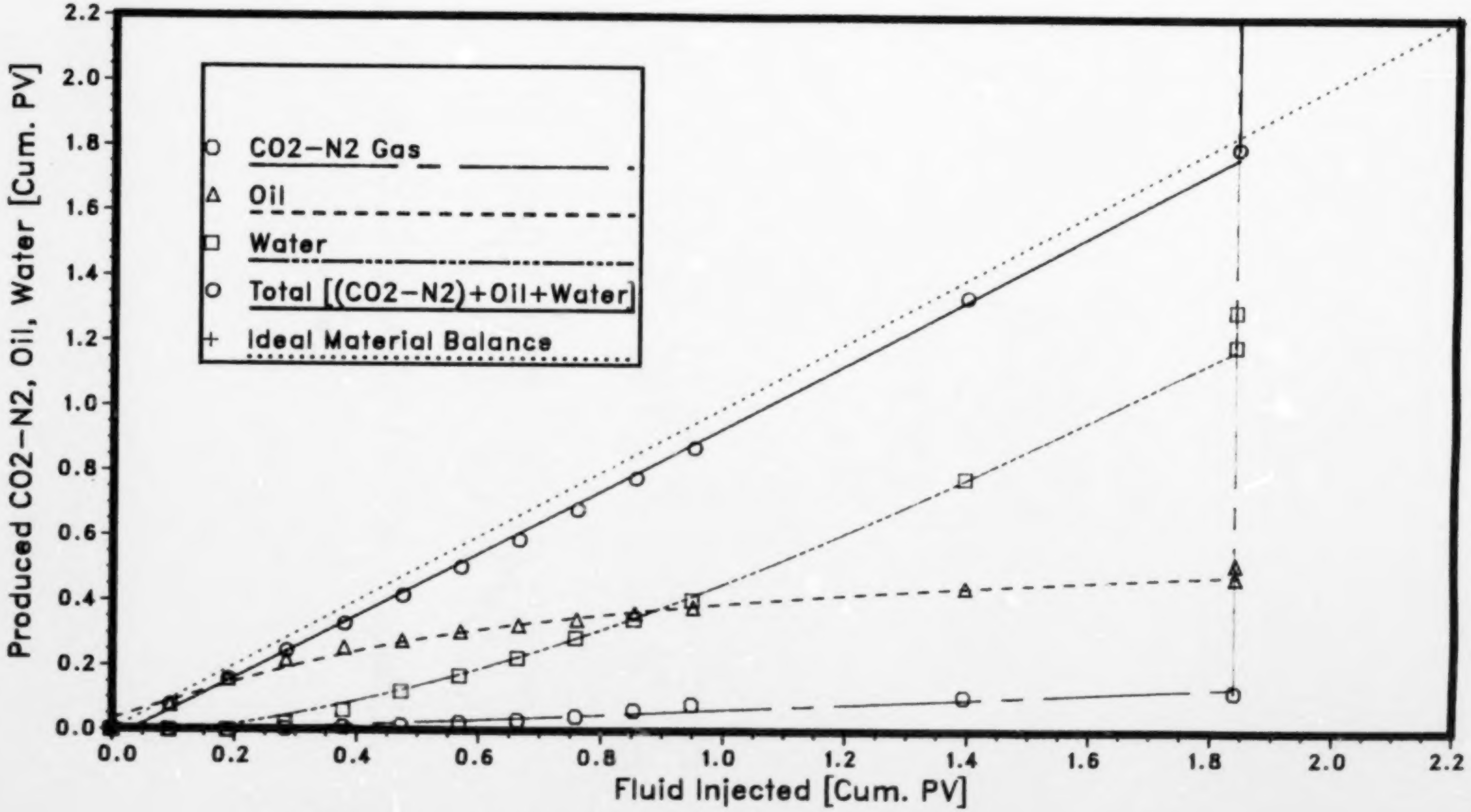
Figure D8 – Volumetric Balance on Run 1DT8.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 36.06 %, k = 11.140 darcies, S_o = 94.71 %, S_{wc} = 5.29 %

[0.20 HCPV CO2−N2 @ 1.00 MPa (0.091 g−mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 9.99%.

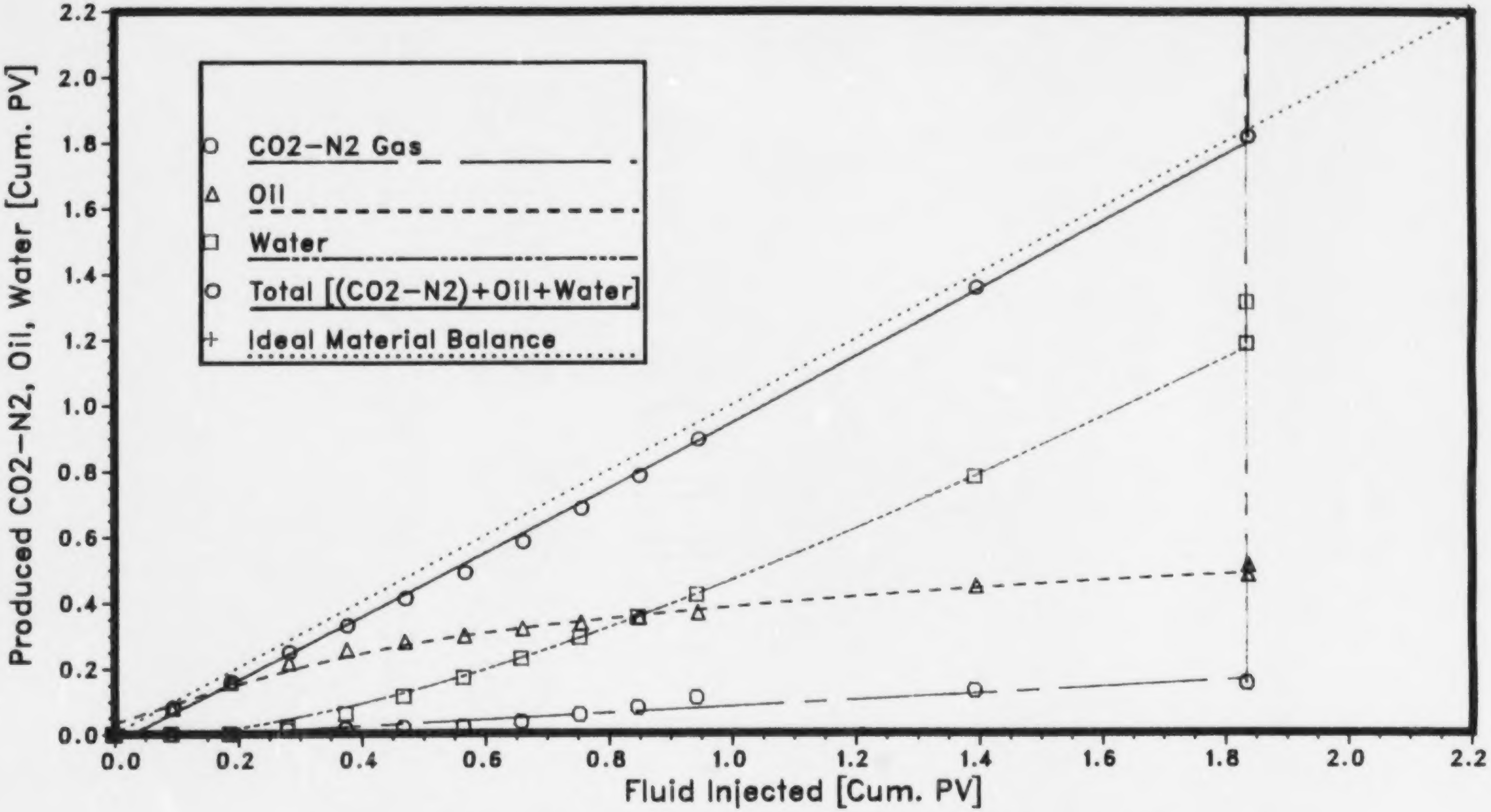
Figure D9 — Volumetric Balance on Run 1DT9.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.73 %, k = 11.530 darcies, S_o = 95.05 %, S_{wc} = 4.95 %

[0.20 HCPV CO2−N2 @ 1.0 MPa (0.090 g−mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.00%

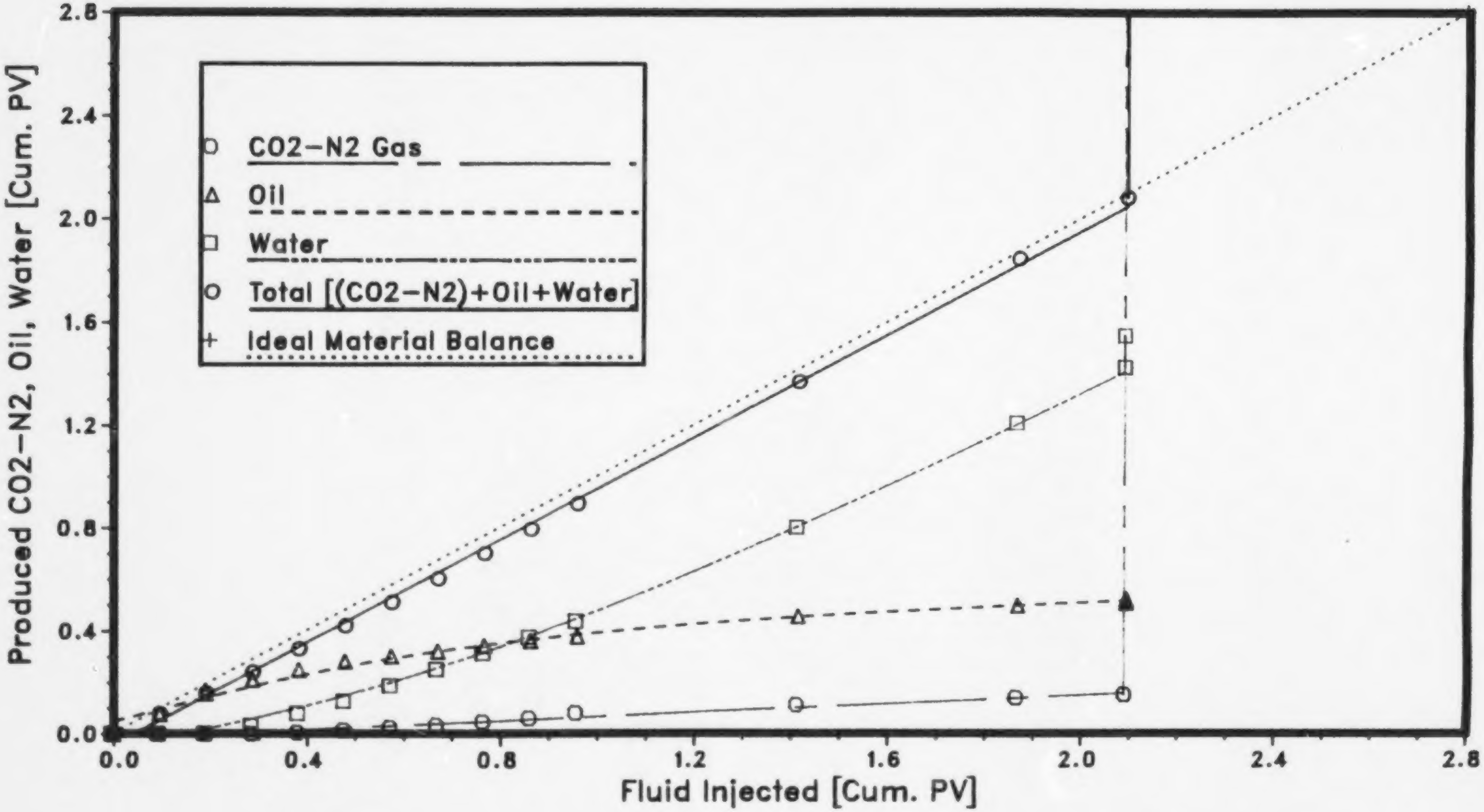
Figure D10 − Volumetric Balance on Run 1DT10.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.77 %, k = 11.890 darcies, S_o = 94.12 %, S_{wc} = 5.88 %

[0.20 HCPV CO2−N2 @ 1.0 MPa (0.089 g−mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 20.00%

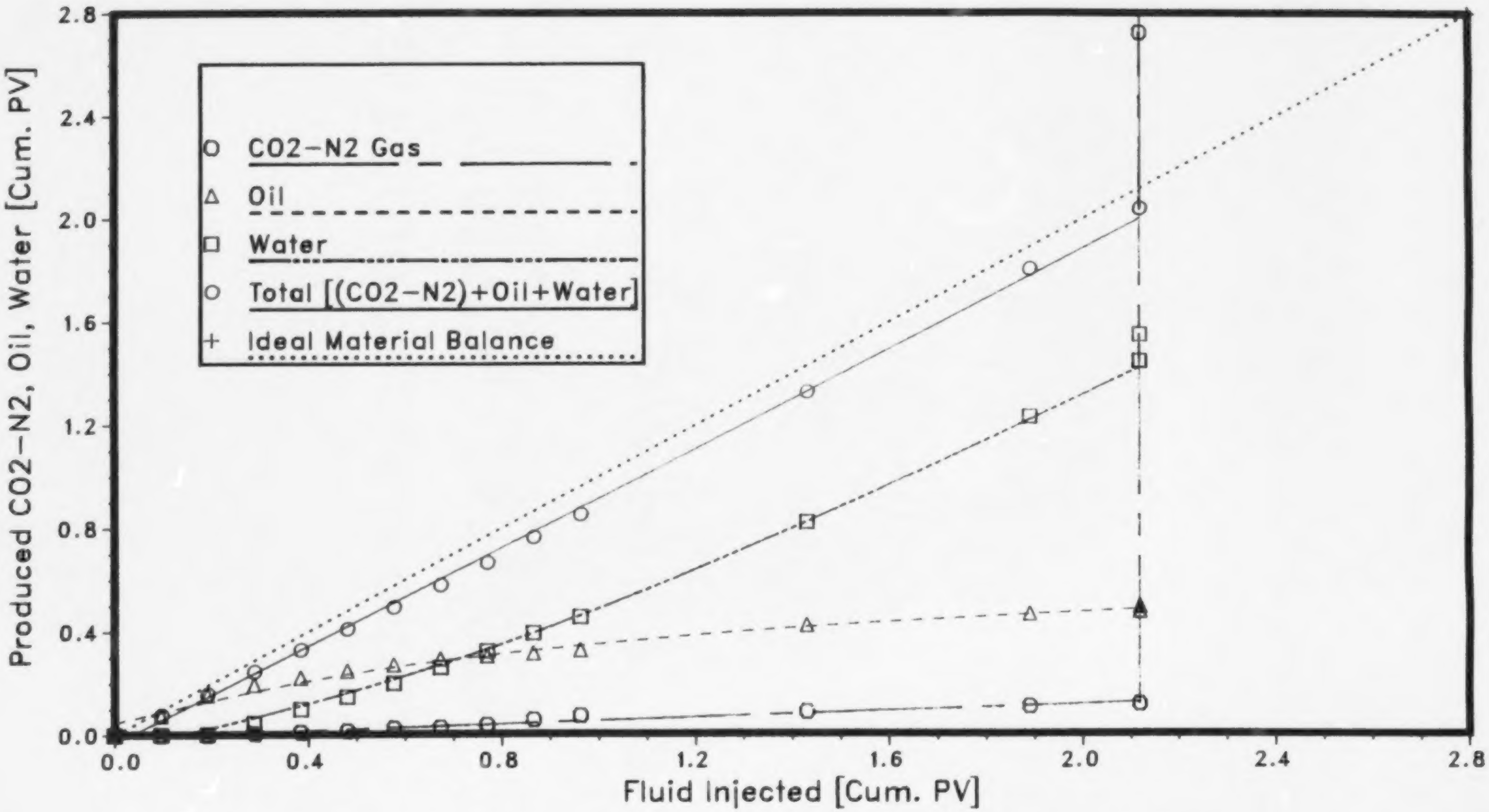
Figure D11 — Volumetric Balance on Run 1DT11.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.77 %, k = 11.430 darcies, S_o = 95.77 %, S_{wc} = 4.23 %

[0.20 HCPV CO2−N2 @ 1.0 MPa (0.091 g−mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 25.00%

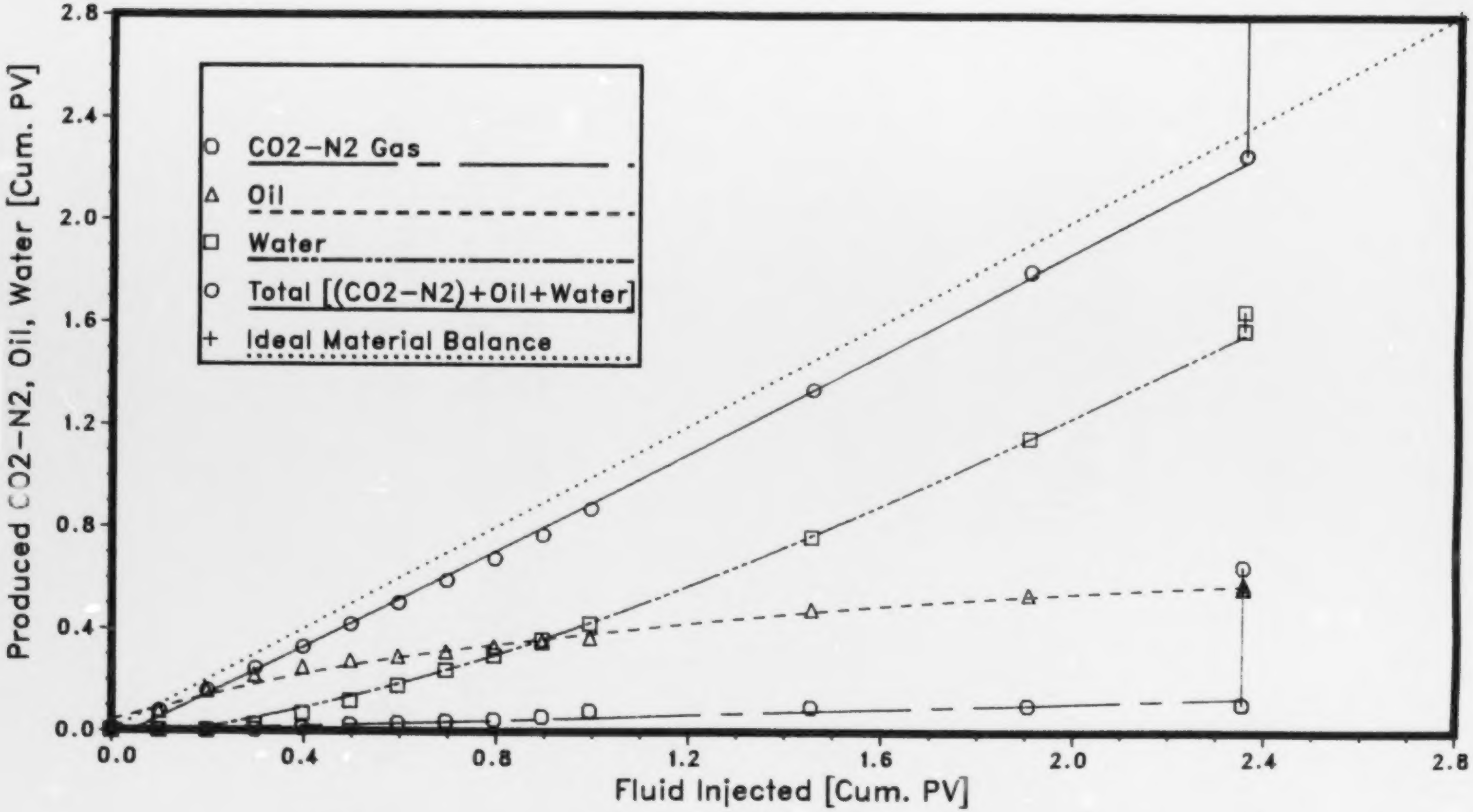
Figure D12 − Volumetric Balance on Run 1DT12.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.22 %, k = 11.090 darcies, S_o = 96.16 %, S_{wc} = 3.84 %

[0.20 HCPV CO2−N2 @ 1.0 MPa (0.089 g−mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 30.00%

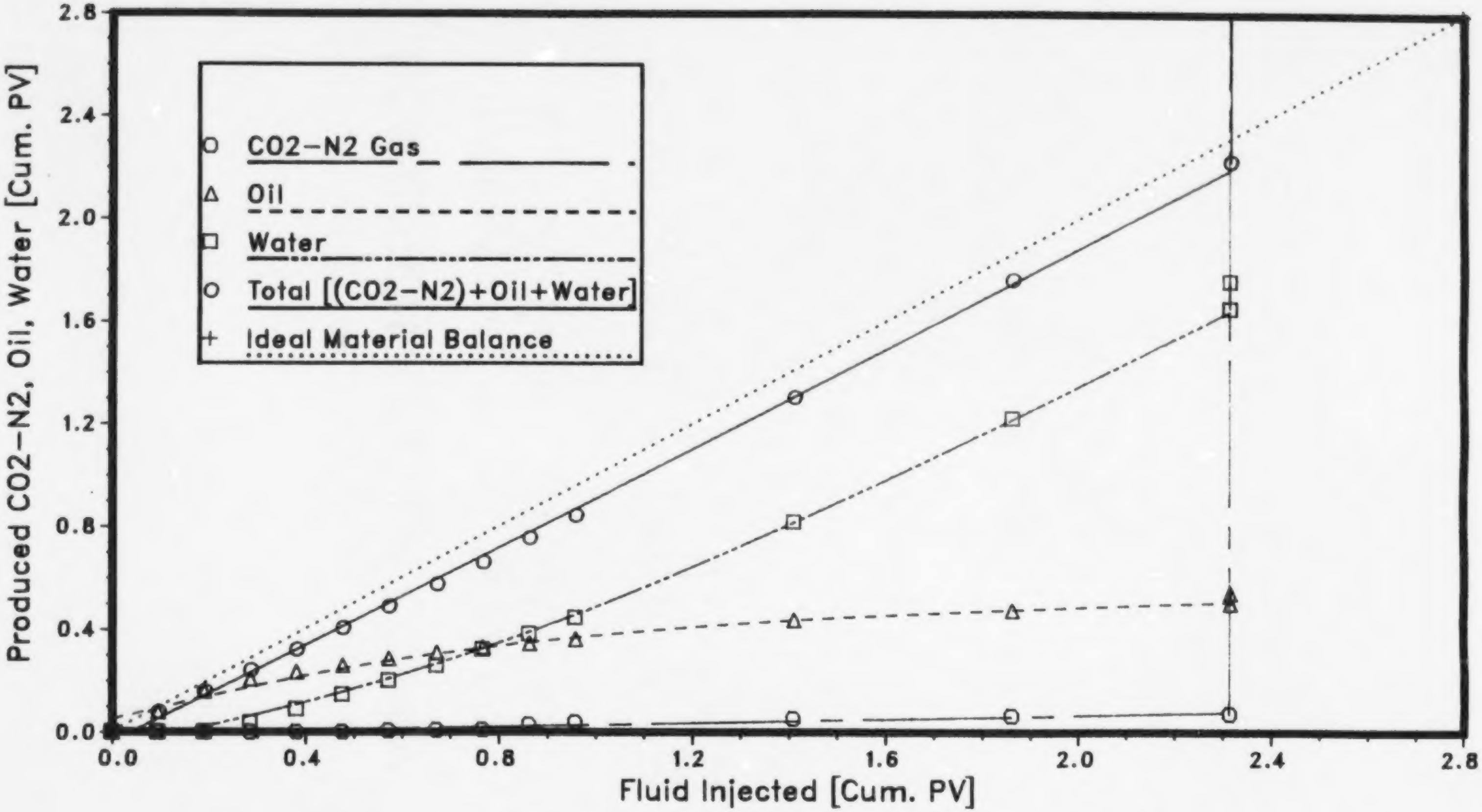
Figure D13 − Volumetric Balance on Run 1DT13.



NOTE: Average Run Conditions: Direct Line Drive, 1.20 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.90 %, k = 11.690 darcies, S_o = 95.51 %, S_{wc} = 4.49 %

[0.20 HCPV CO2−N2 @ 1.2 MPa (0.111 g−mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.00%

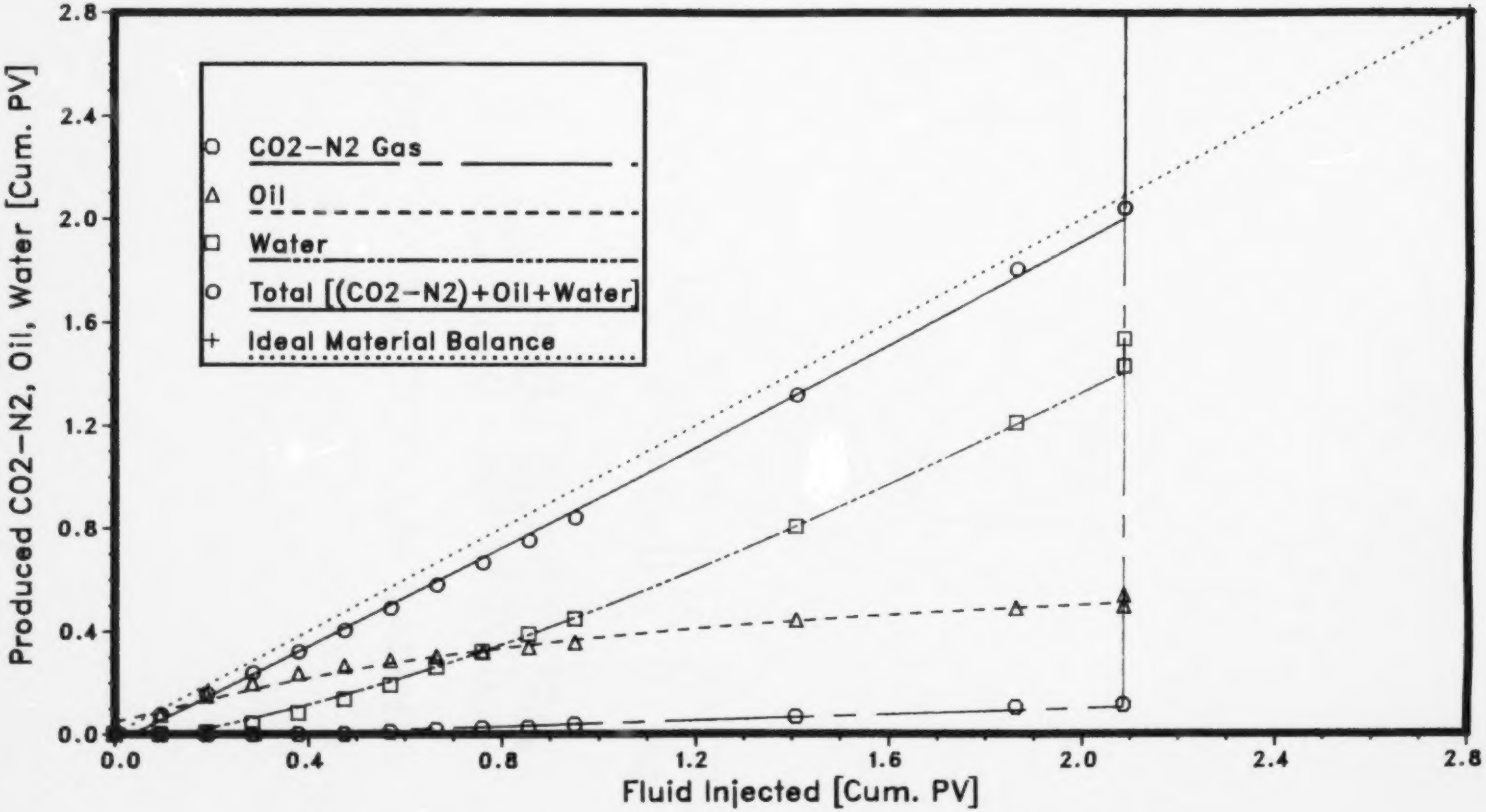
Figure D14 – Volumetric Balance on Run 1DT14.



NOTE: Average Run Conditions: Direct Line Drive, 1.35 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.43 %, k = 10.780 darcies, S_o = 95.46 %, S_{wc} = 4.54 %

[0.20 HCPV CO2−N2 @ 1.35 MPa (0.122 g−mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 25.00%

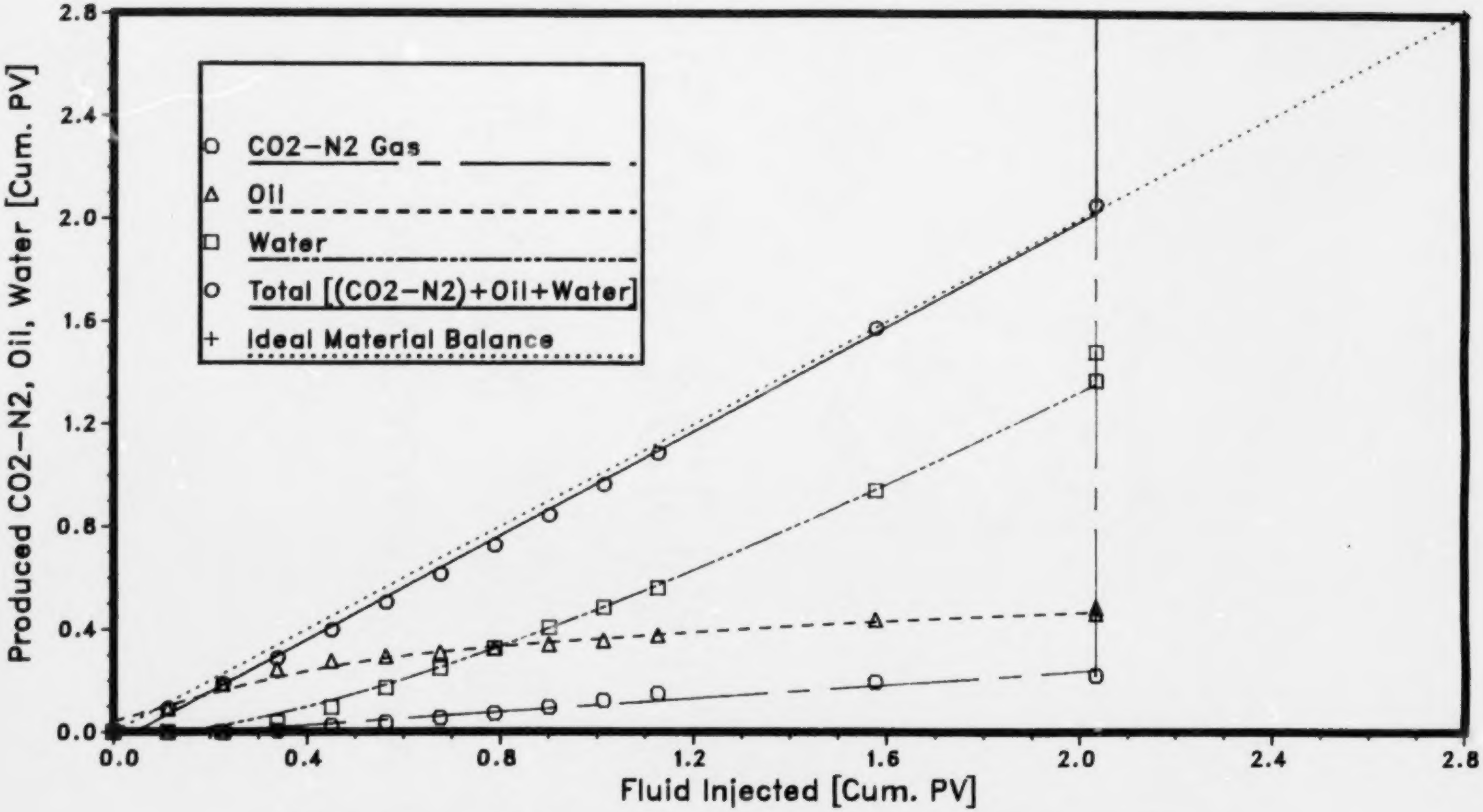
Figure D15 − Volumetric Balance on Run 1DT15.



NOTE: Average Run Conditions: Direct Line Drive, 1.44 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.51 %, k = 10.020 darcies, S_o = 95.12 %, S_{wc} = 4.88 %

[0.20 HCPV CO2−N2 @ 1.44 MPa (0.130 g−mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 30.00%

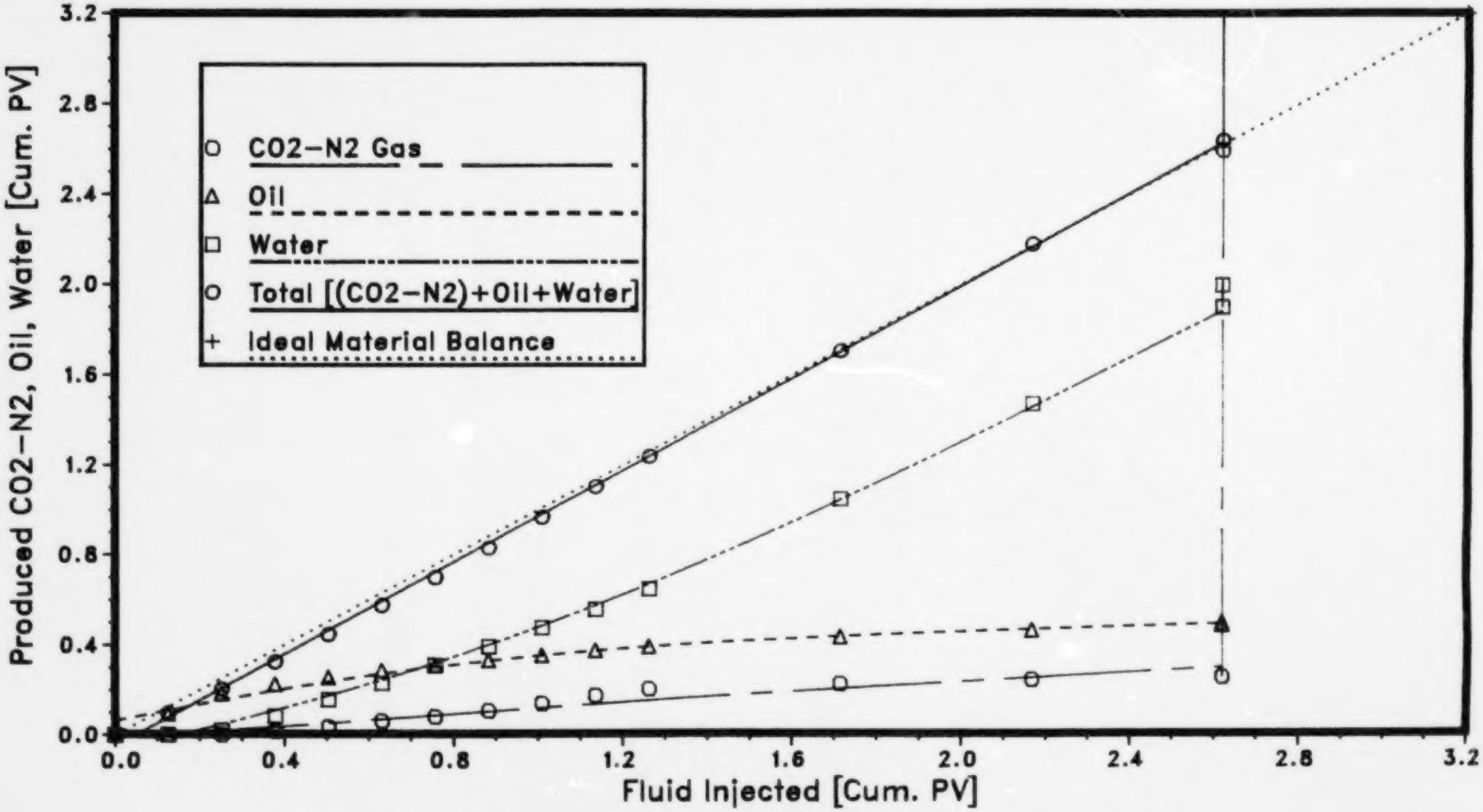
Figure D16 — Volumetric Balance on Run 1DT16.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.61 %, k = 10.240 darcies, S_o = 95.59 %, S_{wc} = 4.41 %

[0.24 HCPV CO2−N2 @ 1.00 MPa (0.106 g−mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.00%

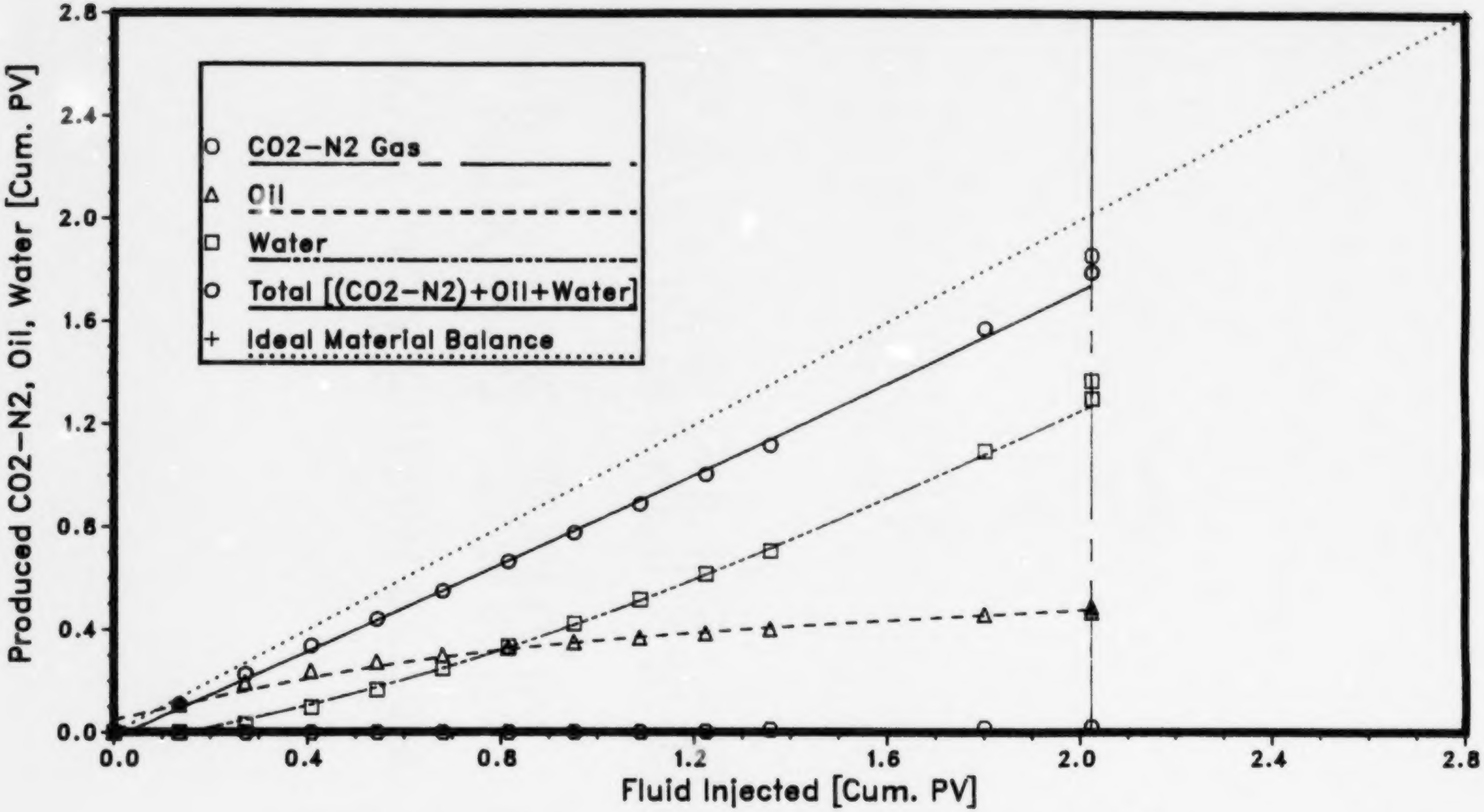
Figure D17 — Volumetric Balance on Run 1DT17.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.64 %, k = 11.280 darcies, S_o = 94.60 %, S_{wc} = 5.40 %

[0.27 HCPV CO2−N2 @ 1.0 MPa (0.119 g−mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 25.00%

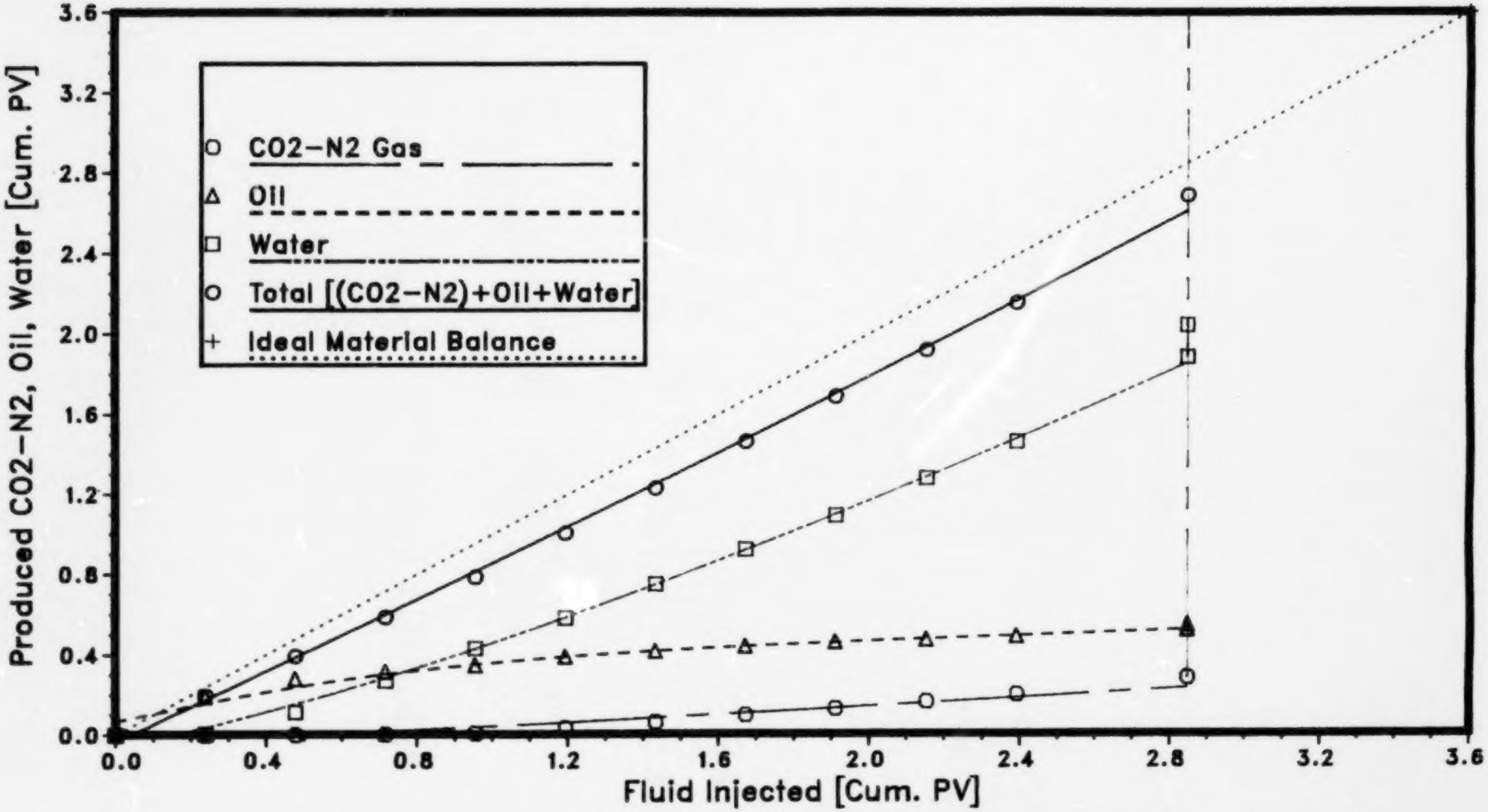
Figure D18 – Volumetric Balance on Run 1DT18.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.91 %, k = 10.990 darcies, S_o = 95.21 %, S_{wc} = 4.79 %

[0.29 HCPV CO2−N2 @ 1.0 MPa (0.129 g−mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 30.00%

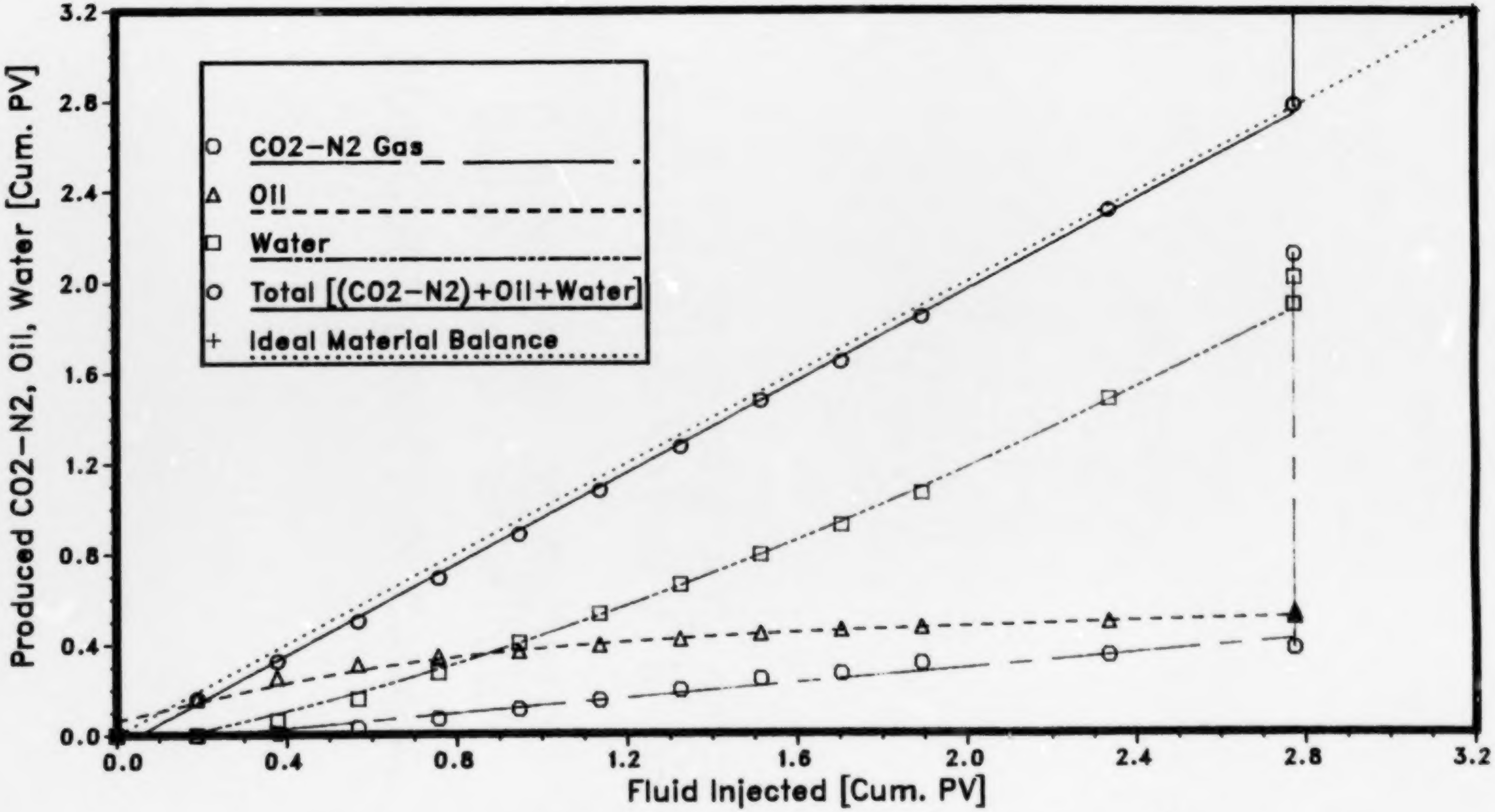
Figure D19 − Volumetric Balance on Run 1DT19.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.61 %, k = 10.890 darcies, S_o = 95.57 %, S_{wc} = 4.43 %

[0.50 HCPV CO2–N2 @ 1.0 MPa (0.227 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 4.98%

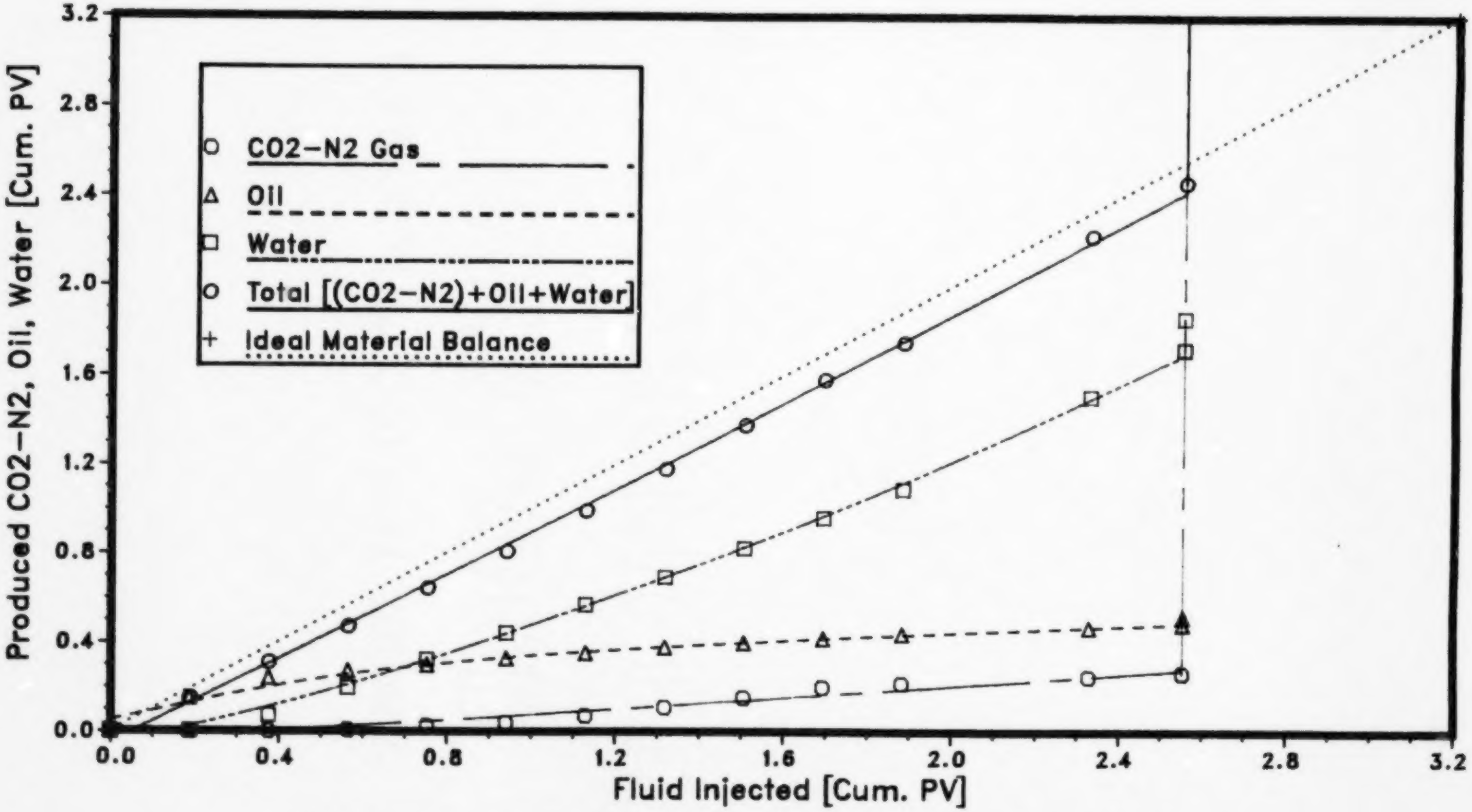
Figure D20 – Volumetric Balance on Run 1DT20.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.93 %, k = 11.450 darcies, S_o = 94.66 %, S_{wc} = 5.34 %

[0.40 HCPV CO2−N2 @ 1.00 MPa (0.180 g−mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 9.99%.

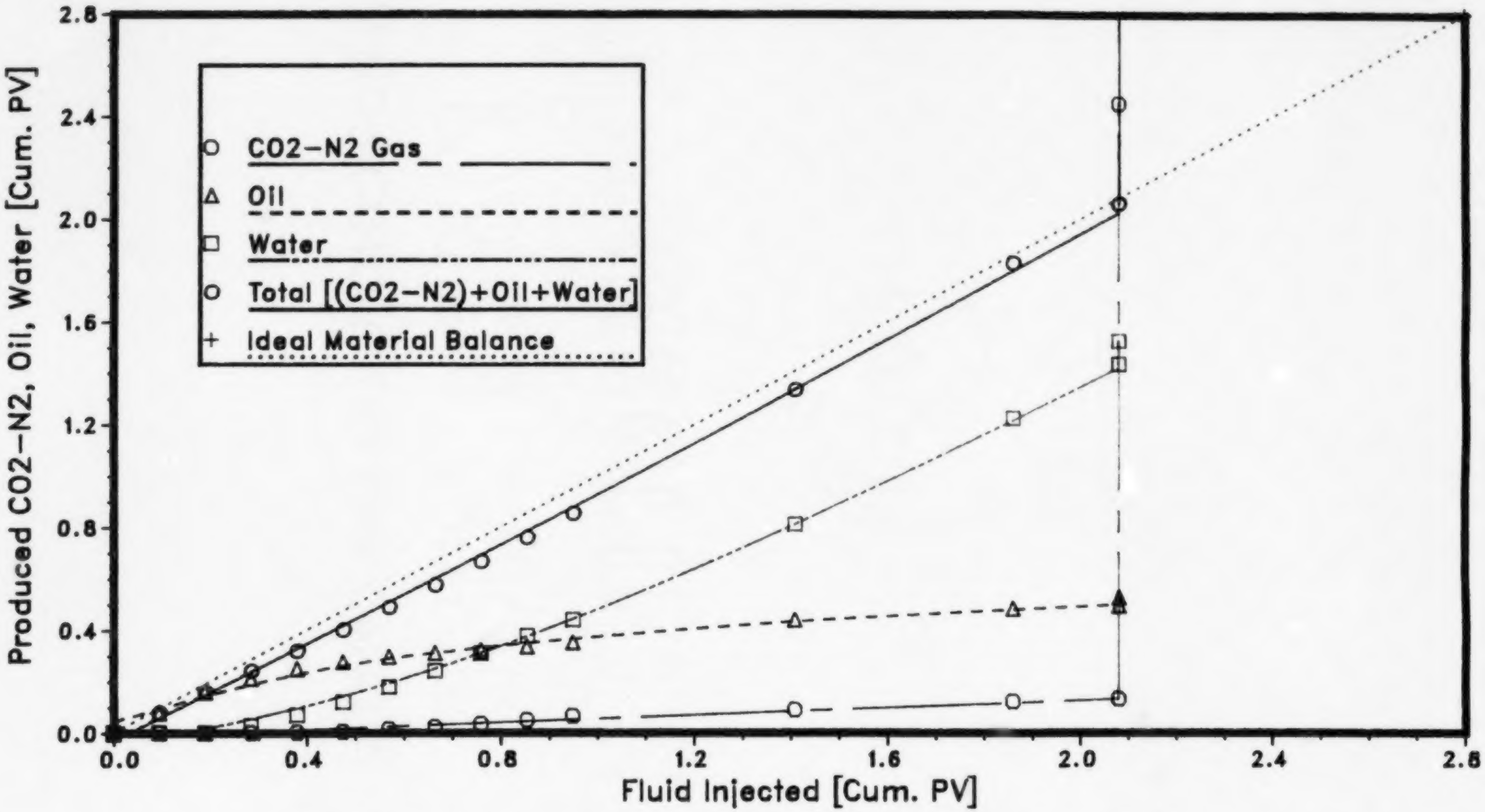
Figure D21 — Volumetric Balance on Run 1DT21.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.83 %, k = 11.050 darcies, S_o = 94.16 %, S_{wc} = 5.84 %

[0.40 HCPV CO2−N2 @ 1.0 MPa (0.178 g−mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.00%

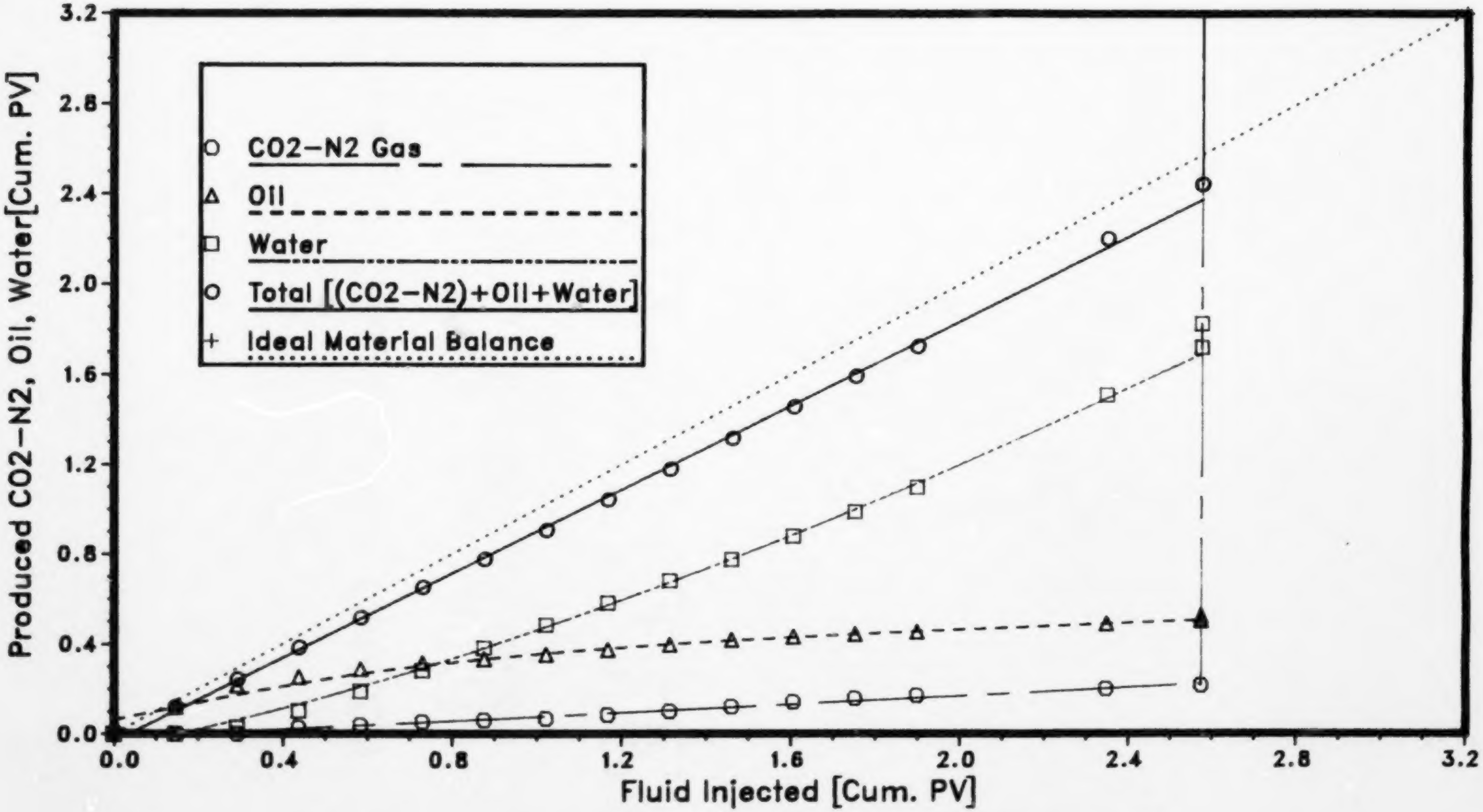
Figure D22 – Volumetric Balance on Run 1DT22.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.73 %, k = 11.220 darcies, S_o = 94.92 %, S_{wc} = 5.08 %

[0.20 HCPV CO2−N2 @ 1.0 MPa (0.090 g−mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 9.99%

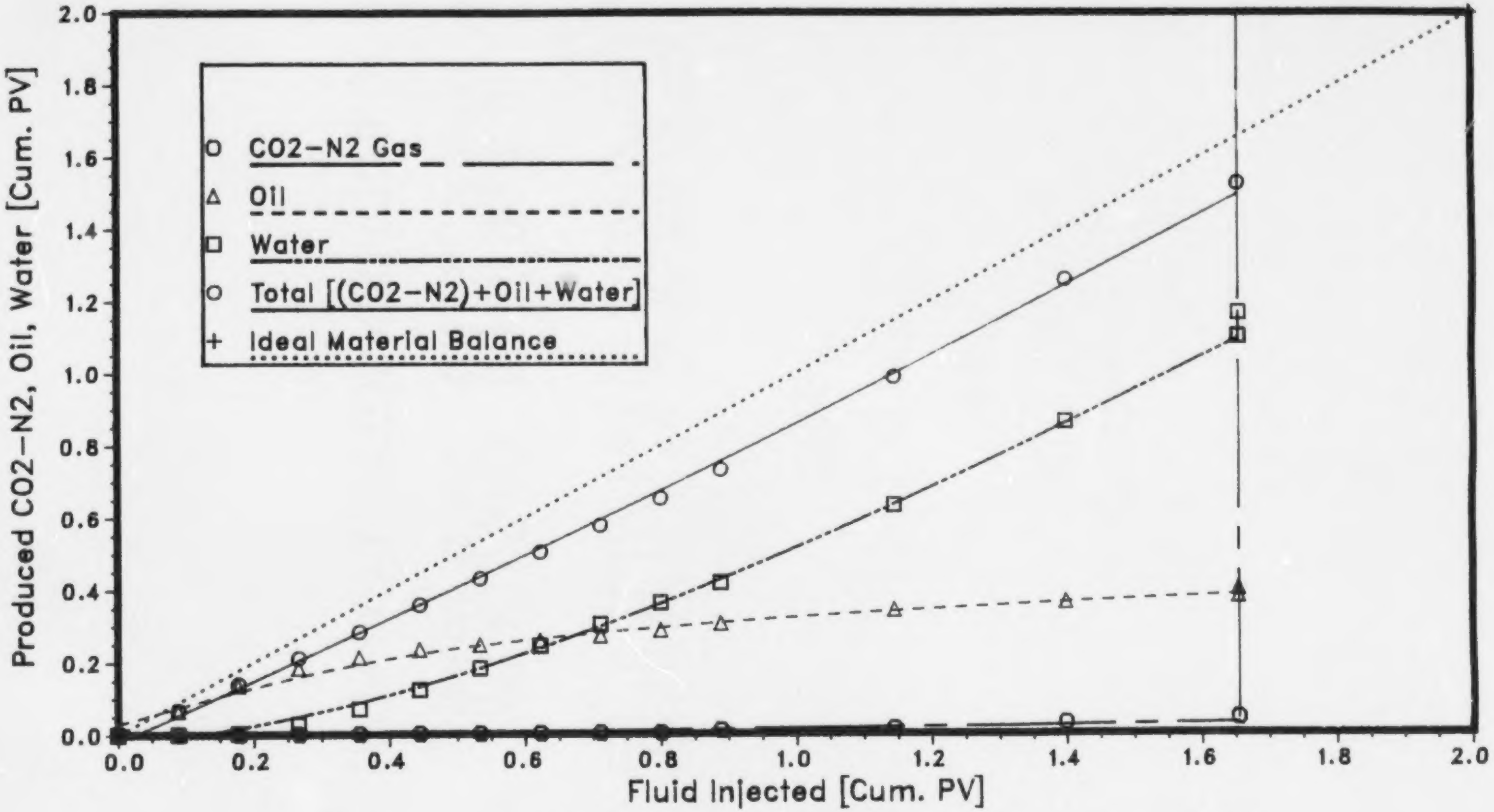
Figure D23 – Volumetric Balance on Run 1DT23.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.59 %, k = 10.900 darcies, S_o = 94.89 %, S_{wc} = 5.11 %

[0.40 HCPV CO2−N2 @ 1.0 MPa (0.178 g−mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.00%

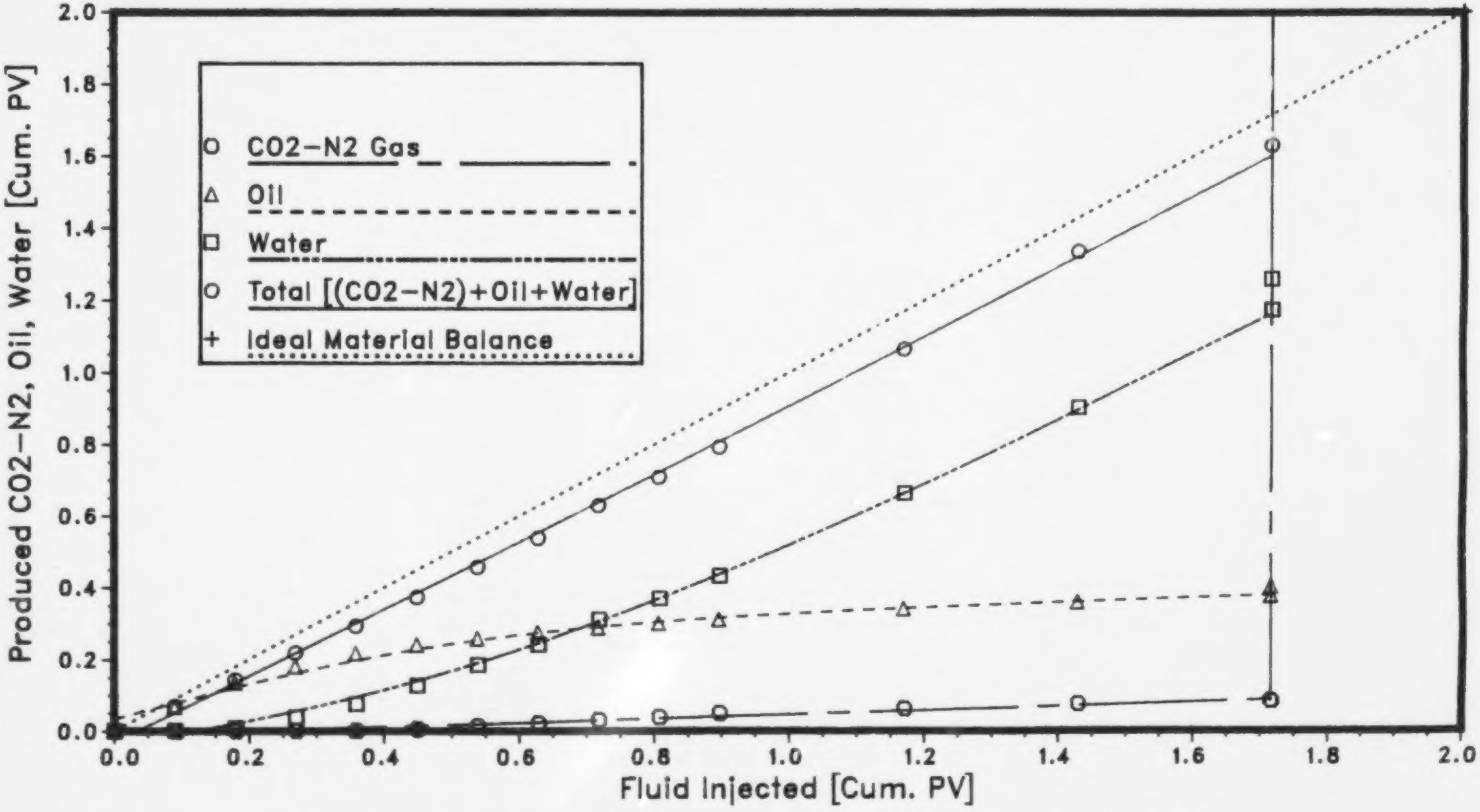
Figure D24 — Volumetric Balance on Run 1DT24.



NOTE: Average Run Conditions: Quarter of a 5−Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 40.77 %, k = 11.140 darcies, S_o = 88.82 %, S_{wc} = 11.18 %

[0.20 HCPV CO2−N2 @ 1.0 MPa (0.152 g−mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 4.98%

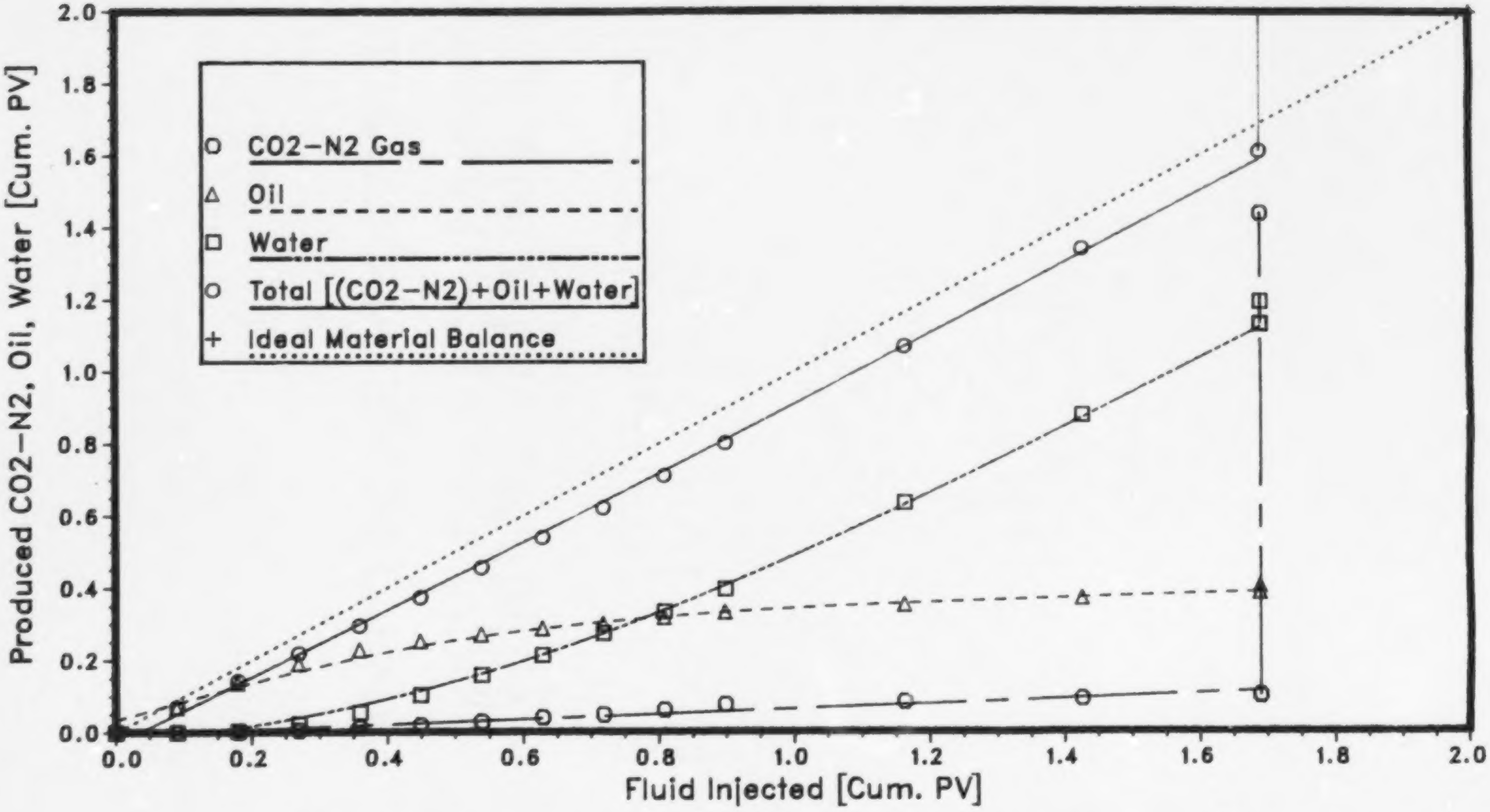
Figure D25 – Volumetric Balance on Run 2DT1.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 40.14 %, k = 11.120 darcies, S_o = 89.51 %, S_{wc} = 10.49 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.150 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 9.99%

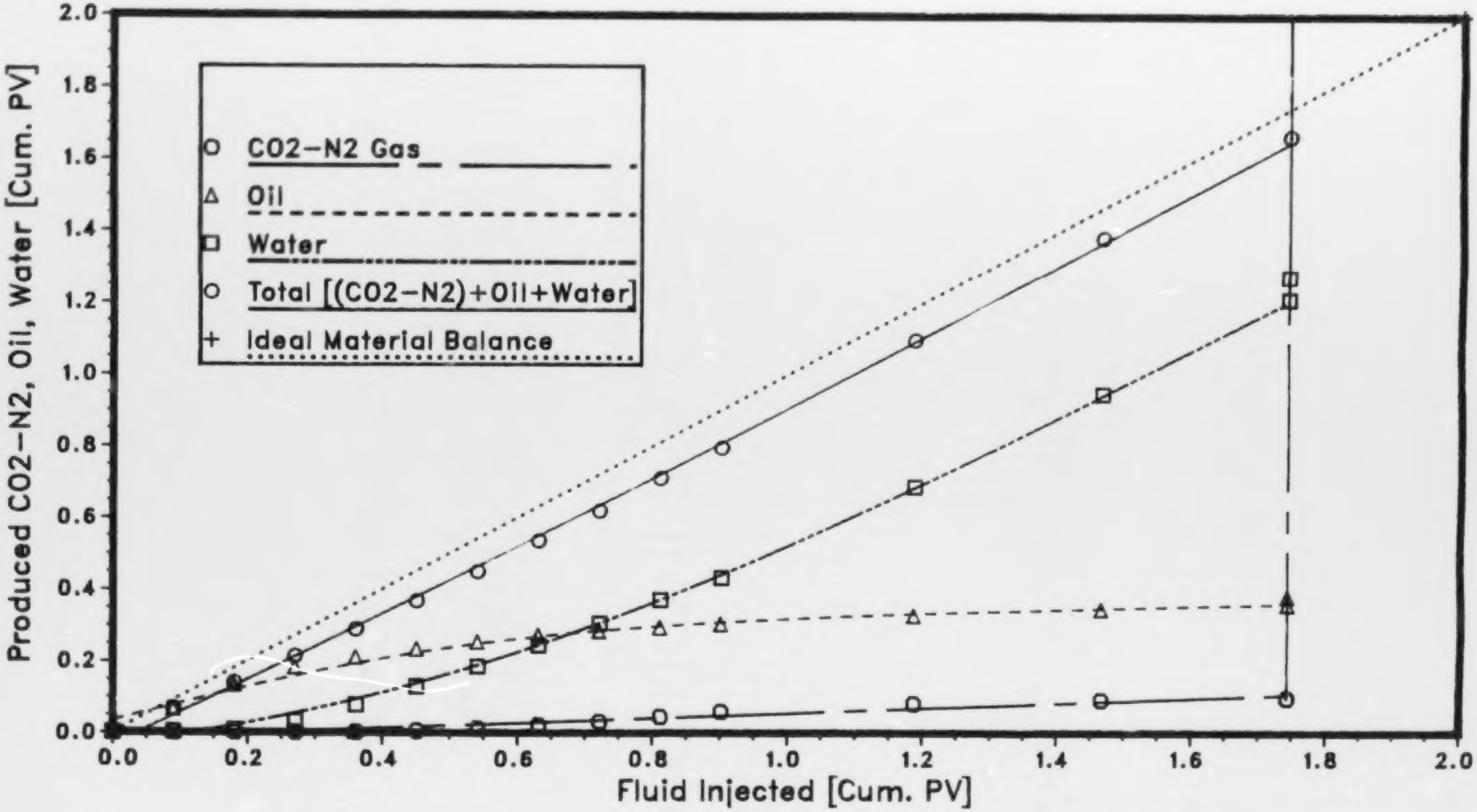
Figure D26 – Volumetric Balance on Run 2DT2.



NOTE: Average Run Conditions: Quarter of a 5−Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 39.48 %, k = 11.220 darcies, S_o = 89.93 %, S_{wc} = 10.07 %

[0.20 HCPV CO2−N2 @ 1.0 MPa (0.148 g−mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.00%

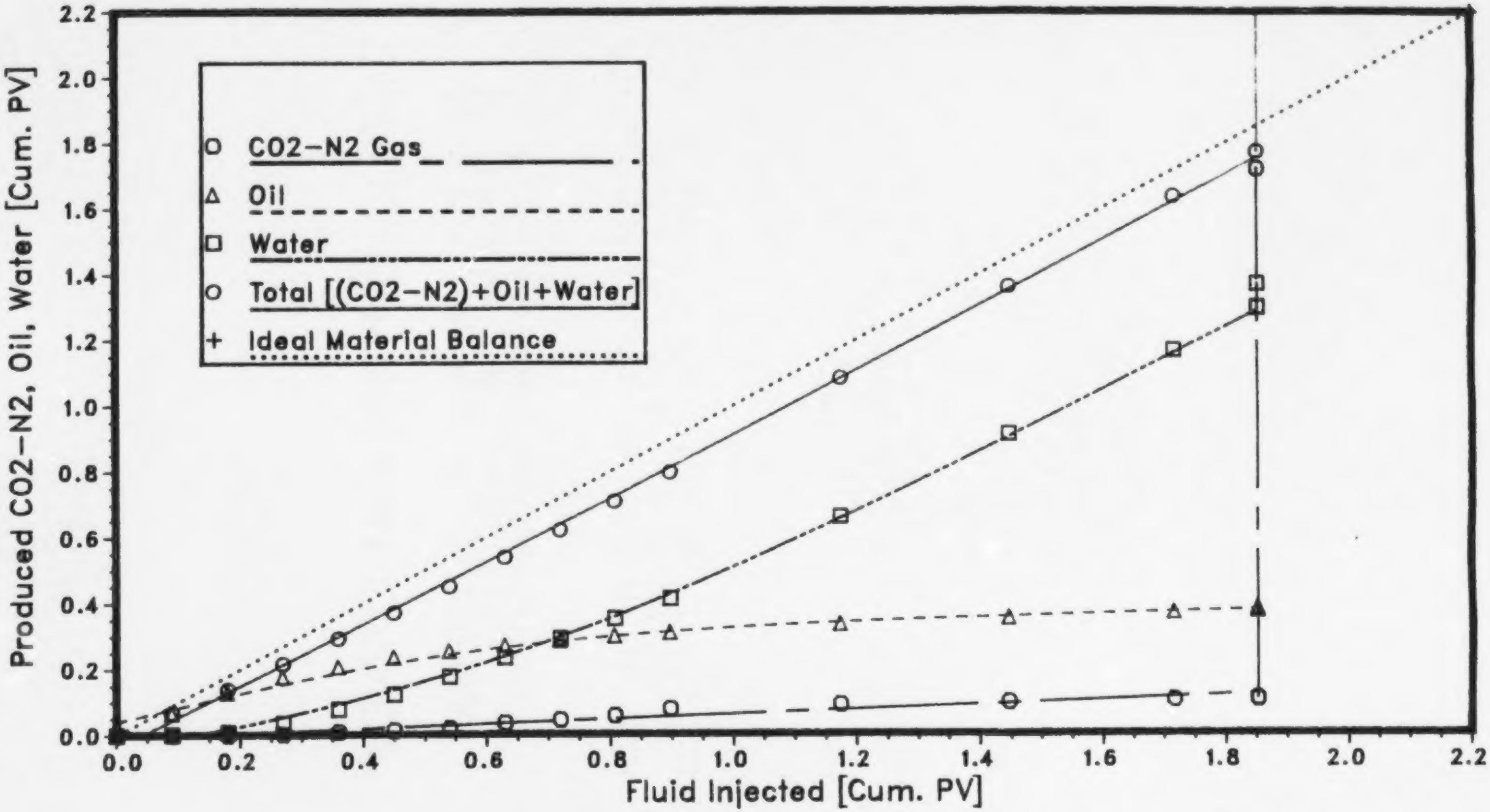
Figure D27 − Volumetric Balance on Run 2DT3.



NOTE: Average Run Conditions: Quarter of a 5−Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 37.16 %, k = 12.790 darcies, S_o = 90.14 %, S_{wc} = 9.86 %

[0.20 HCPV CO2−N2 @ 1.0 MPa (0.139 g−mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 20.00%

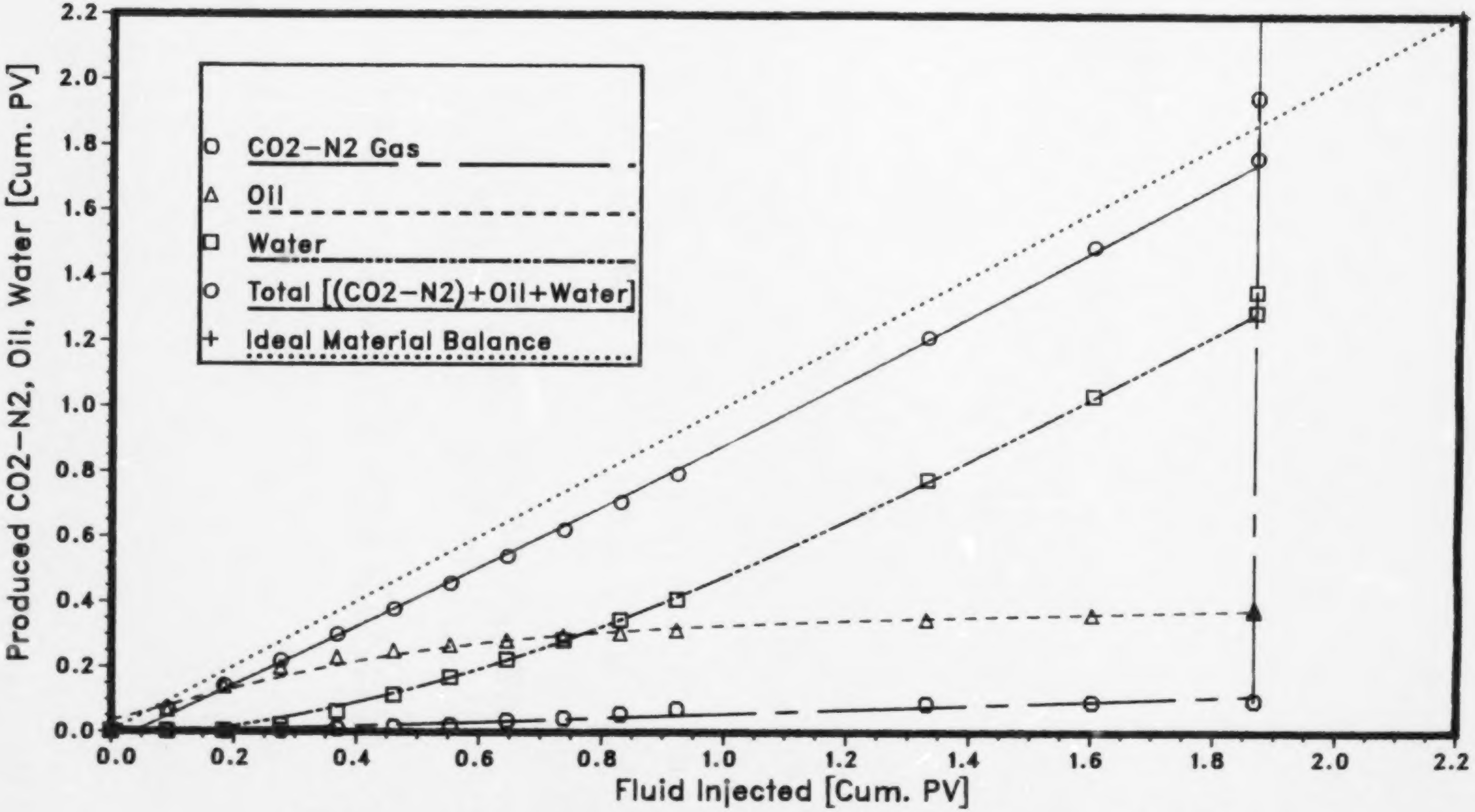
Figure D28 − Volumetric Balance on Run 2DT4.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 38.00 %, k = 14.040 darcies, S_o = 89.95 %, S_{wc} = 10.05 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.142 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 25.00%

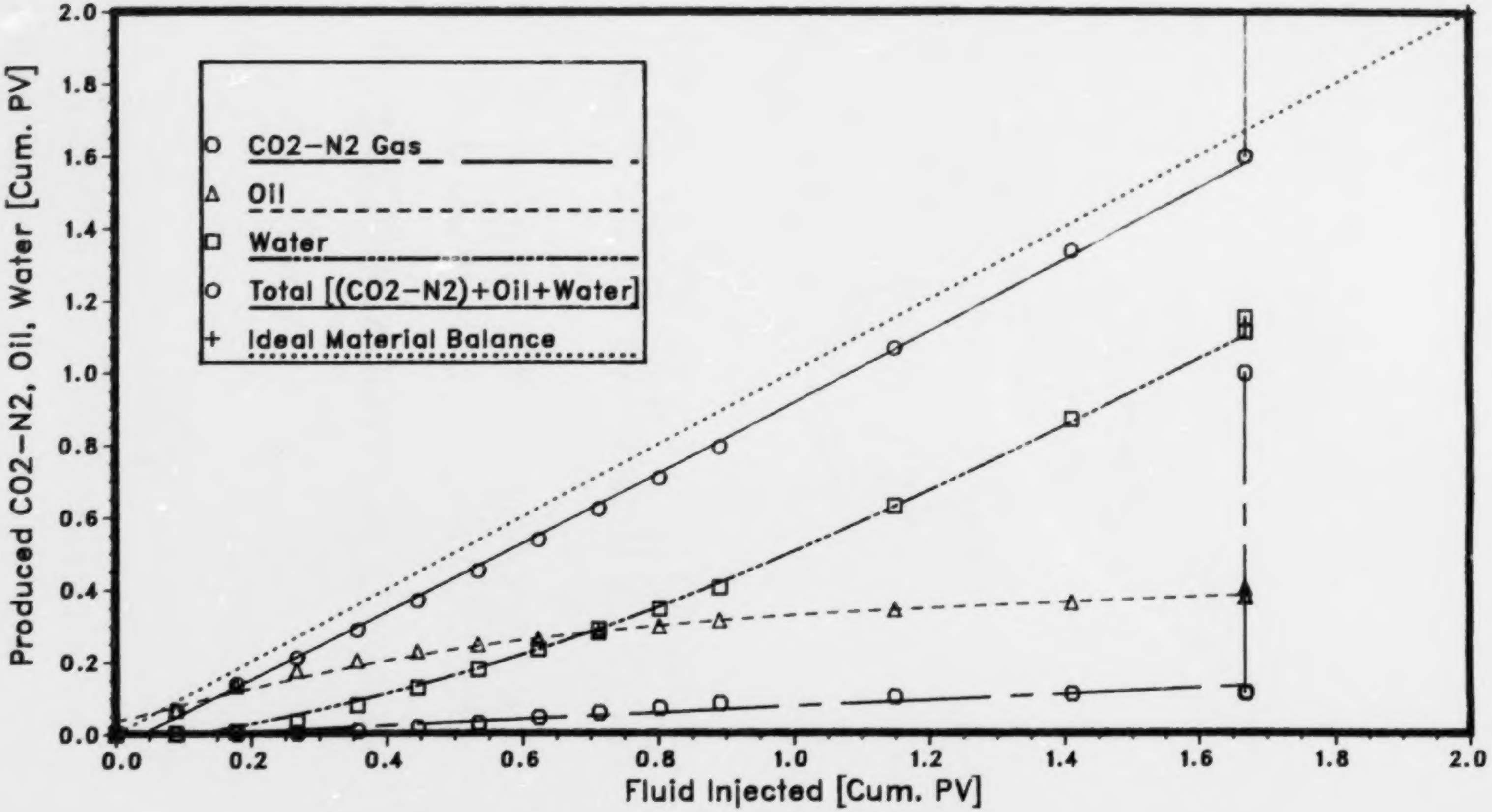
Figure D29 — Volumetric Balance on Run 2DT5.



NOTE: Average Run Conditions: Quarter of a 5−Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 38.25 %, k = 12.960 darcies, S_o = 92.30 %, S_{wc} = 7.70 %

[0.20 HCPV CO2−N2 @ 1.0 MPa (0.146 g−mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 30.00%

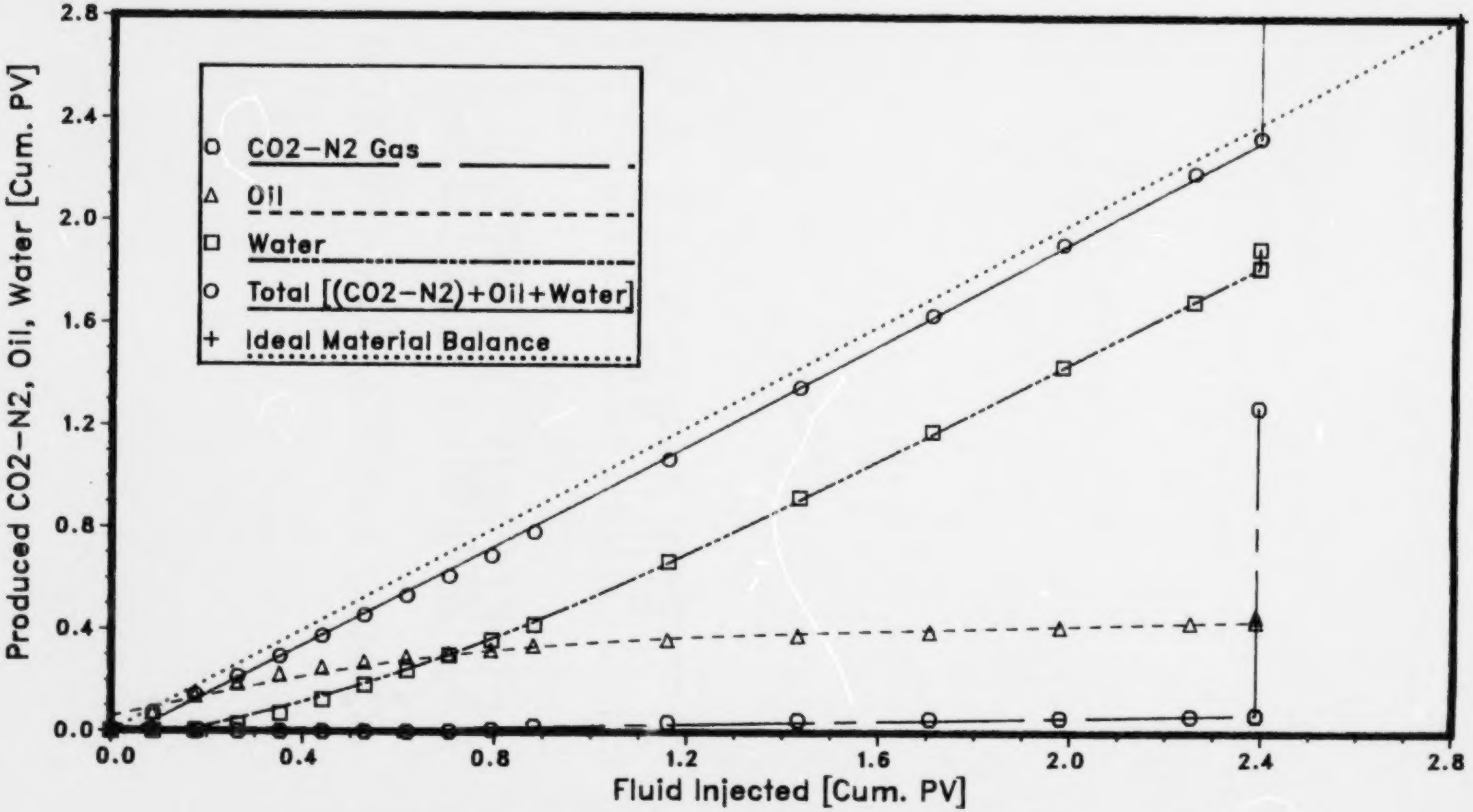
Figure D30 — Volumetric Balance on Run 2DT6.



NOTE: Average Run Conditions: Quarter of a 5−Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 40.44 %, k = 11.020 darcies, S_o = 88.98 %, S_{wc} = 11.79 %

[0.20 HCPV CO2−N2 @ 1.0 MPa (0.151 g−mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 4.98%

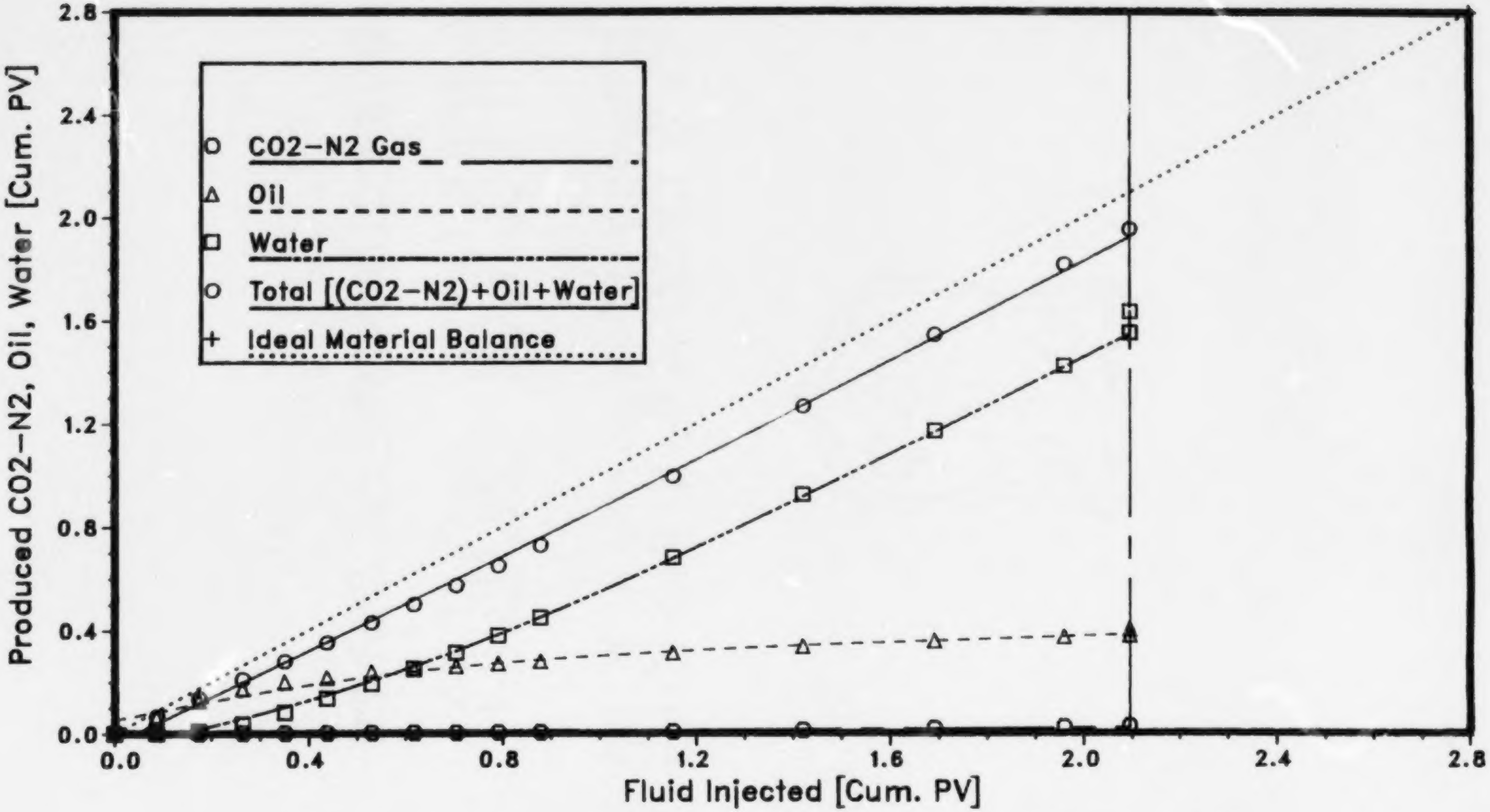
Figure D31 − Volumetric Balance on Run 2DT7.



NOTE: Average Run Conditions: Quarter of a 5−Spot, 1.20 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 37.71 %, k = 11.610 darcies, S_o = 88.11 %, S_{wc} = 11.89 %

[0.20 HCPV CO2−N2 @ 1.2 MPa (0.168 g−mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.00%

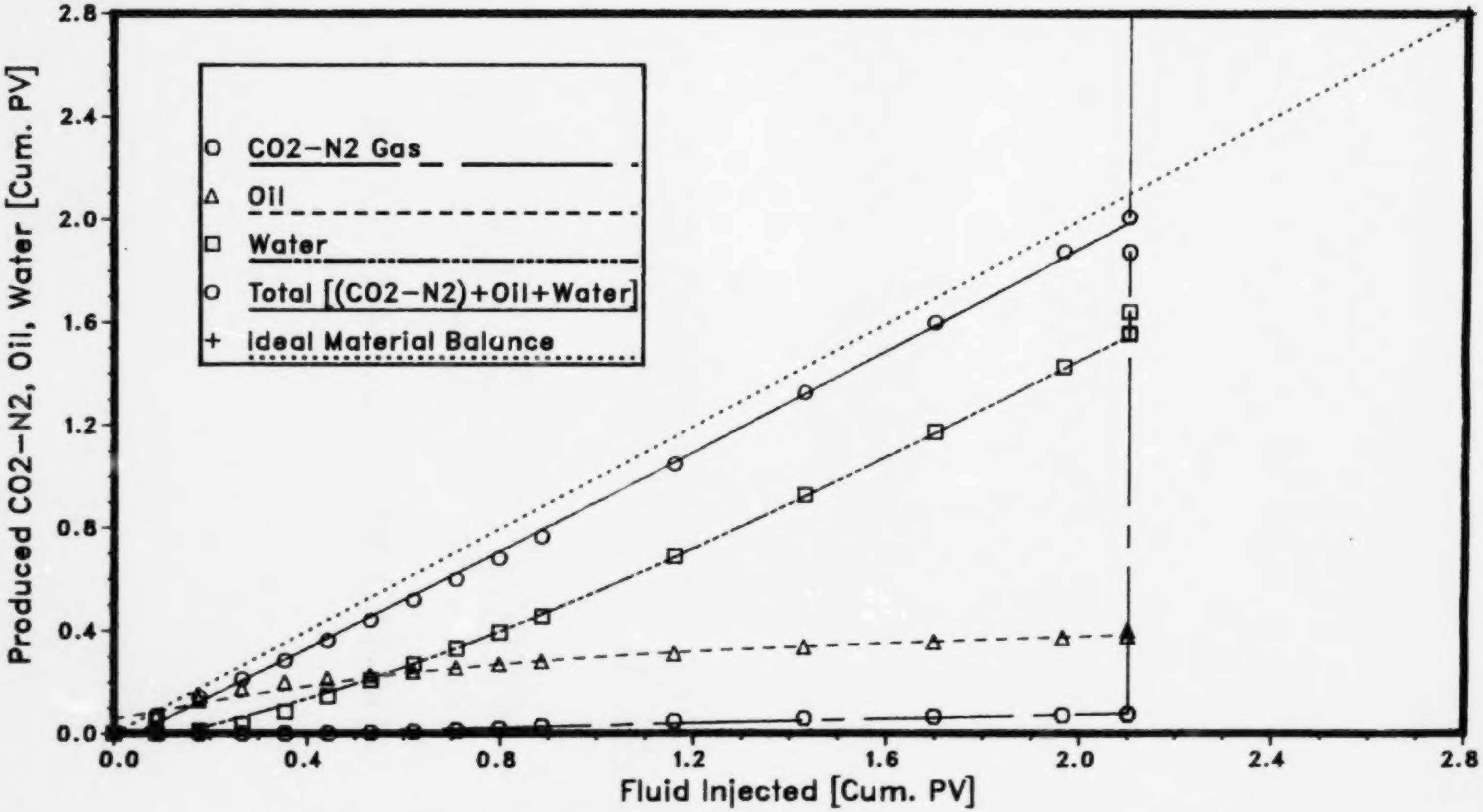
Figure D32 − Volumetric Balance on Run 2DT8.



NOTE: Average Run Conditions: Quarter of a 5−Spot, 1.25 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 38.60 %, k = 12.960 darcies, S_o = 87.04 %, S_{wc} = 11.17 %

[0.20 HCPV CO2−N2 @ 1.25 MPa (0.176 g−mol) 4:1 WAG,10 Slugs,DEAD OIL]
N2 Concentration in Mixture = 20.00%

Figure D33 — Volumetric Balance on Run 2DT9.



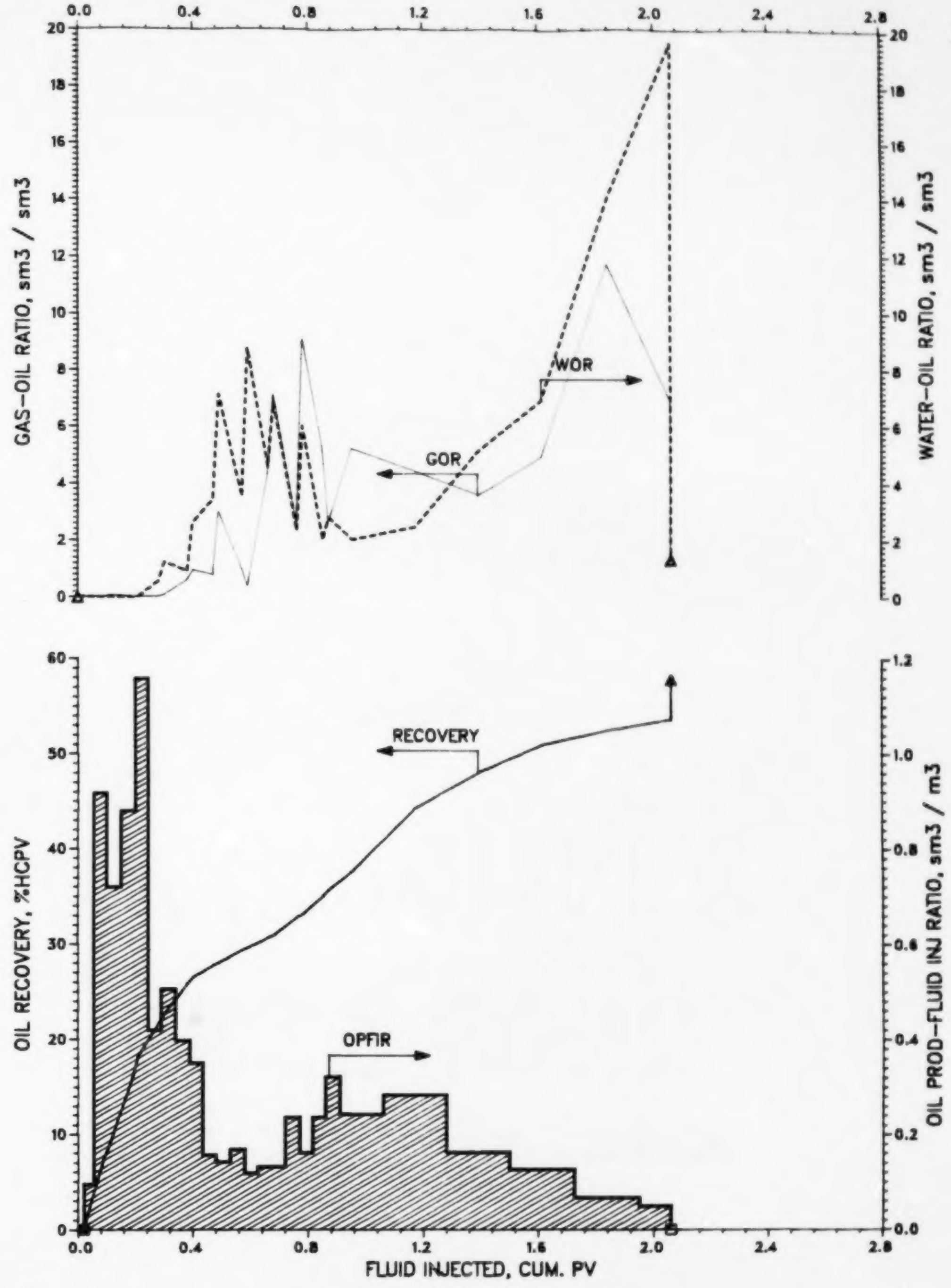
NOTE: Average Run Conditions: Quarter of a 5−Spot, 1.44 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 38.80 %, k = 11.400 darcies, S_o = 88.60 %, S_{wc} = 11.91 %

[0.20 HCPV CO2−N2 @ 1.44 MPa (0.208 g−mol) 4:1 WAG,10 Slugs,DEAD OIL]
N2 Concentration in Mixture = 30.00%

Figure D34 − Volumetric Balance on Run 2DT10.

APPENDIX E

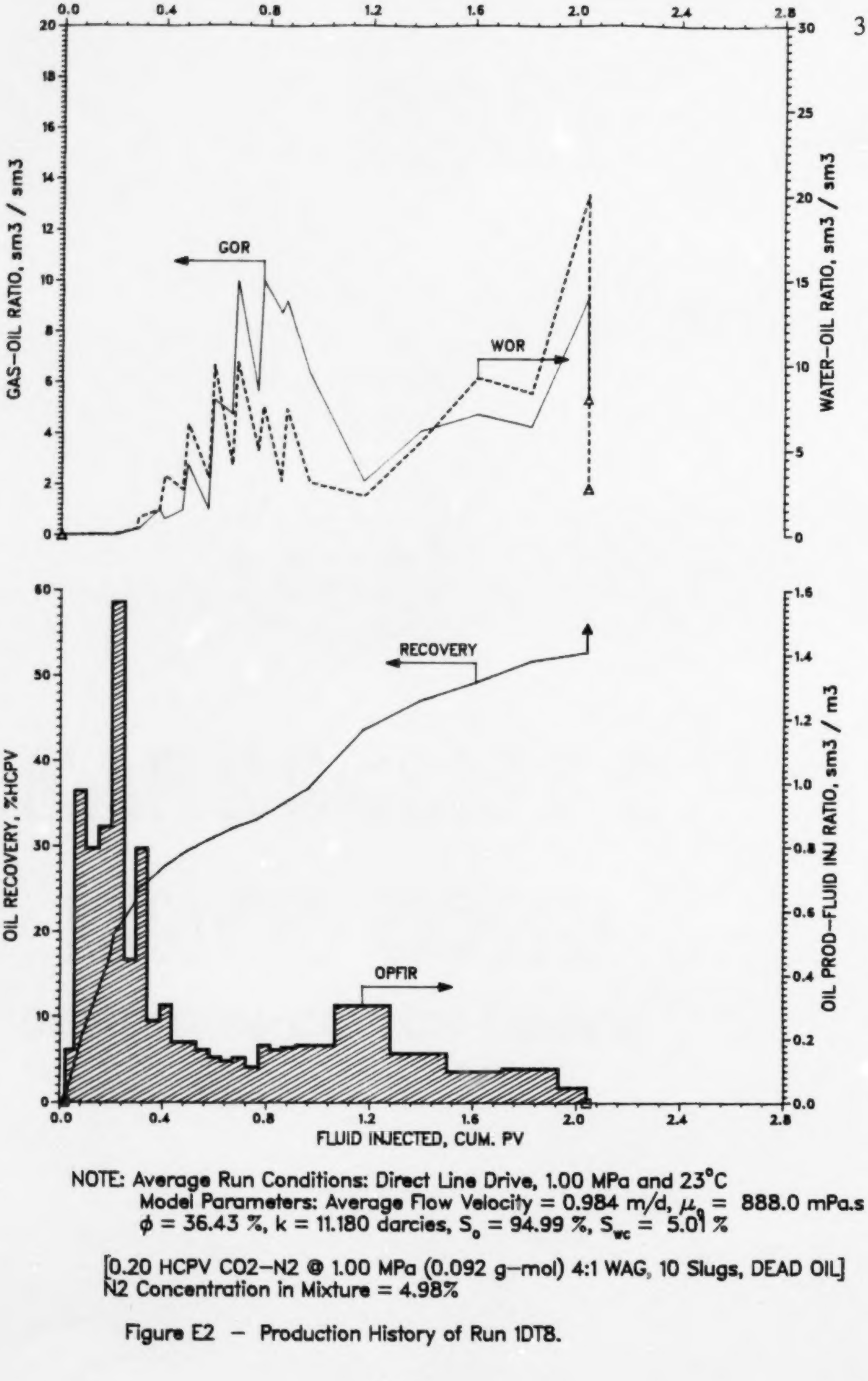
Production Histories of All Experiments Conducted



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.83 %, k = 11.040 darcies, S_o = 94.98 %, S_{wc} = 5.02 %

[0.20 HCPV CO2 @ 1.0 MPa (0.092 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]

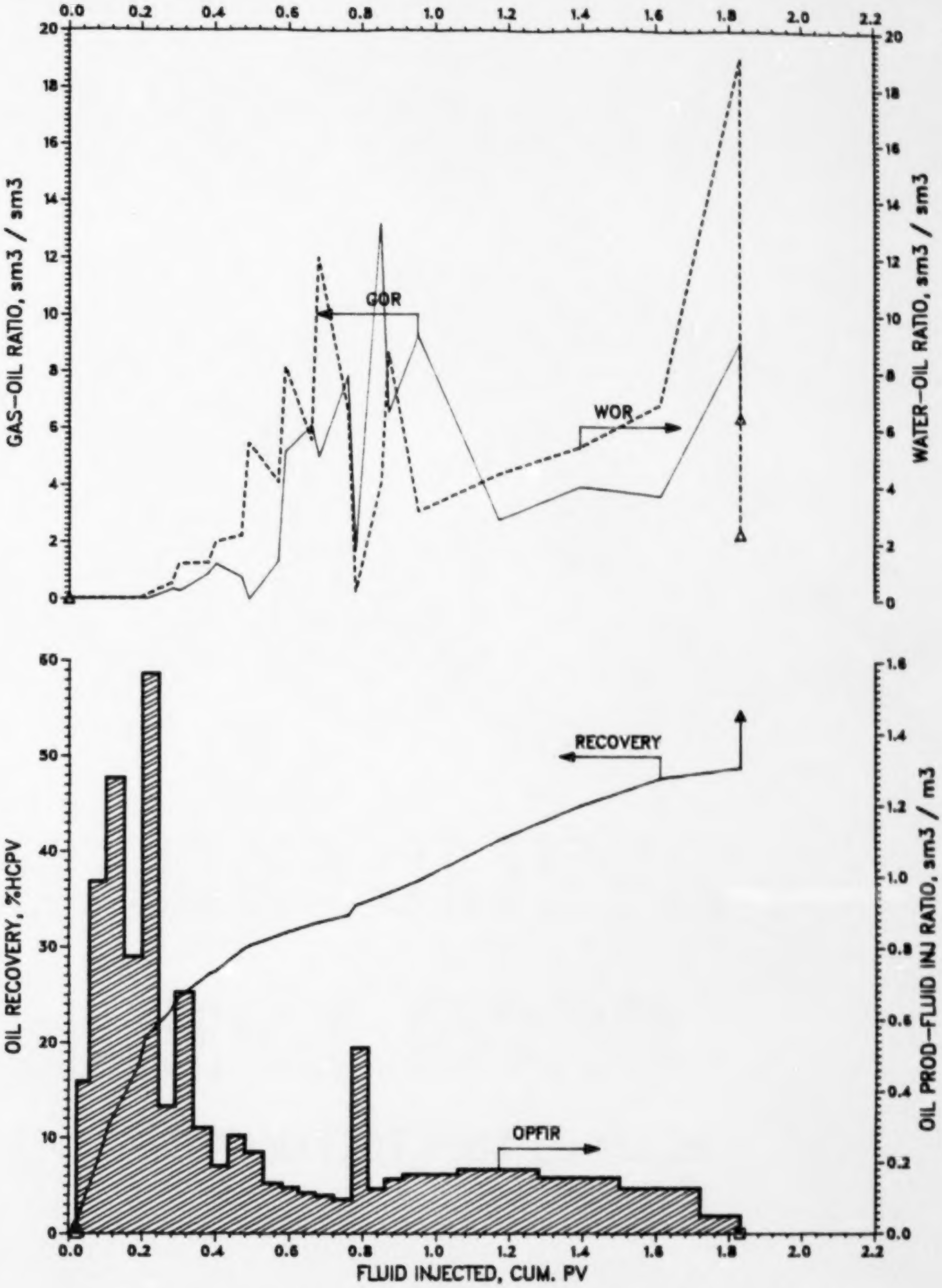
Figure E1 – Production History of Run 1DT7.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 36.43 %, k = 11.180 darcies, S_o = 94.99 %, S_{wc} = 5.01 %

[0.20 HCPV CO2–N2 @ 1.00 MPa (0.092 g-mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 4.98%

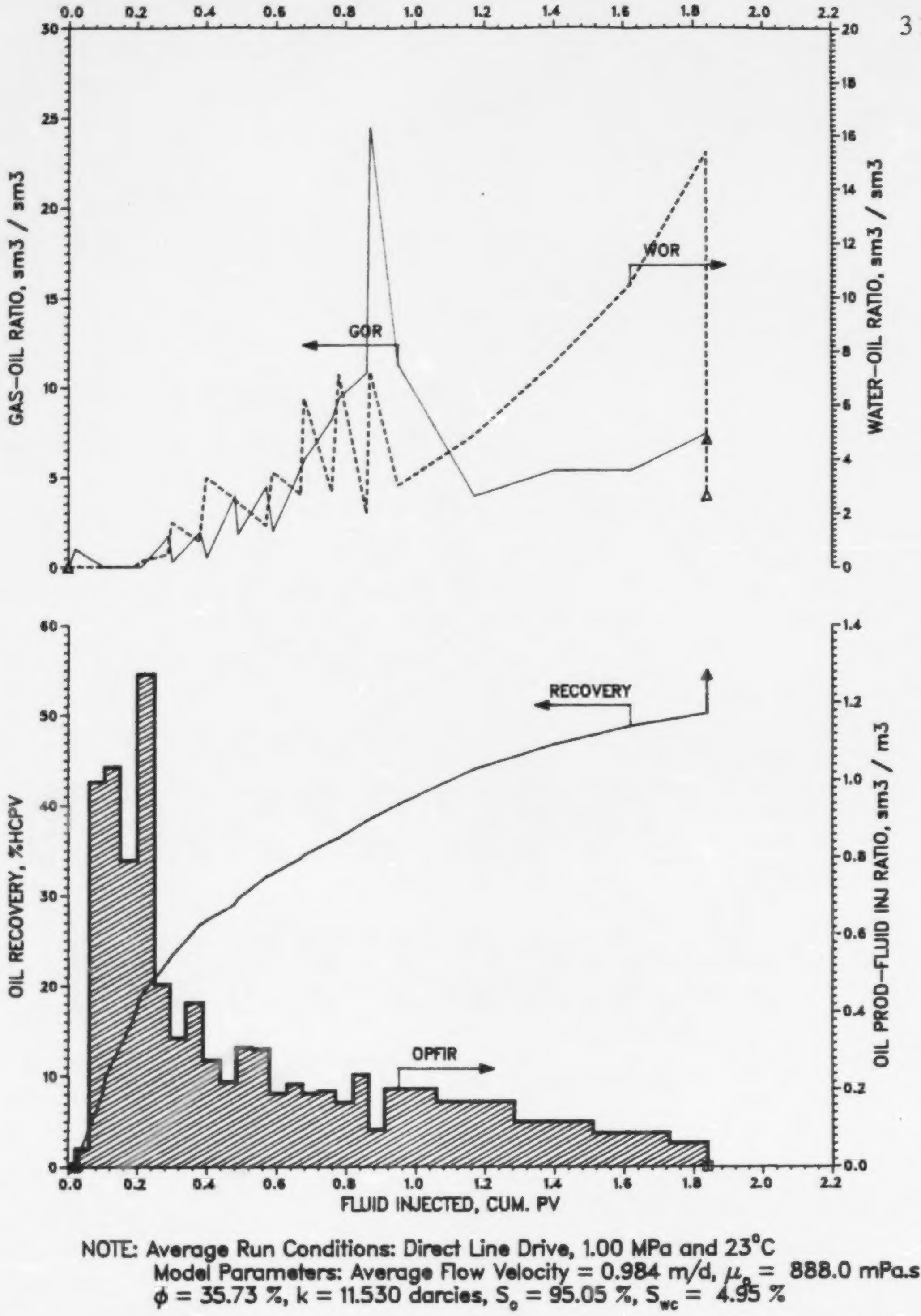
Figure E2 – Production History of Run 1DT8.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 36.06 %, k = 11.140 darcies, S_o = 94.71 %, S_{wc} = 5.29 %

[0.20 HCPV CO2–N2 @ 1.00 MPa (0.091 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 9.99%

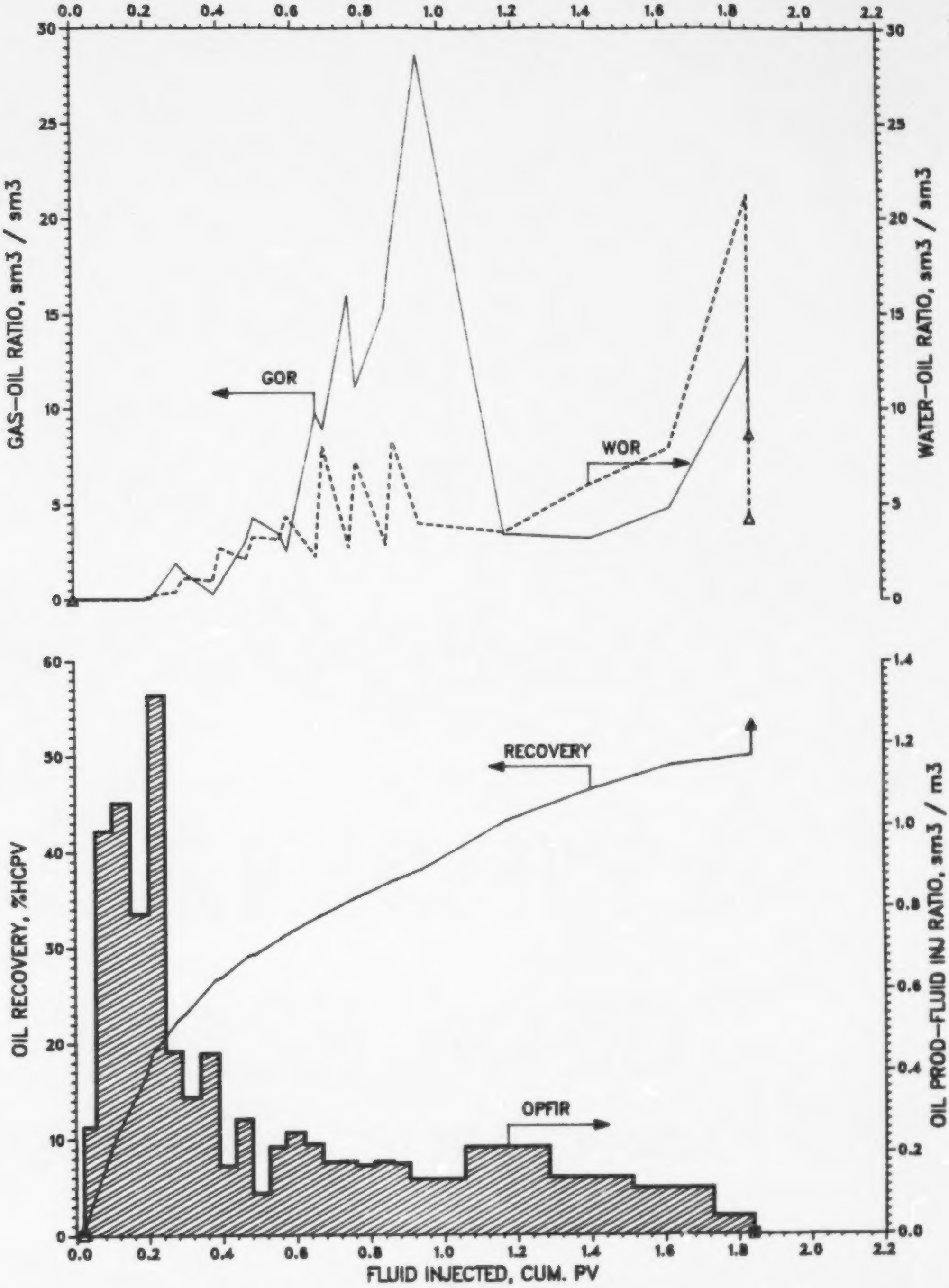
Figure E3 – Production History of Run 1DT9.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.73 %, k = 11.530 darcies, S_o = 95.05 %, S_{wc} = 4.95 %

[0.20 HCPV CO2–N2 @ 1.00 MPa (0.090 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.00%

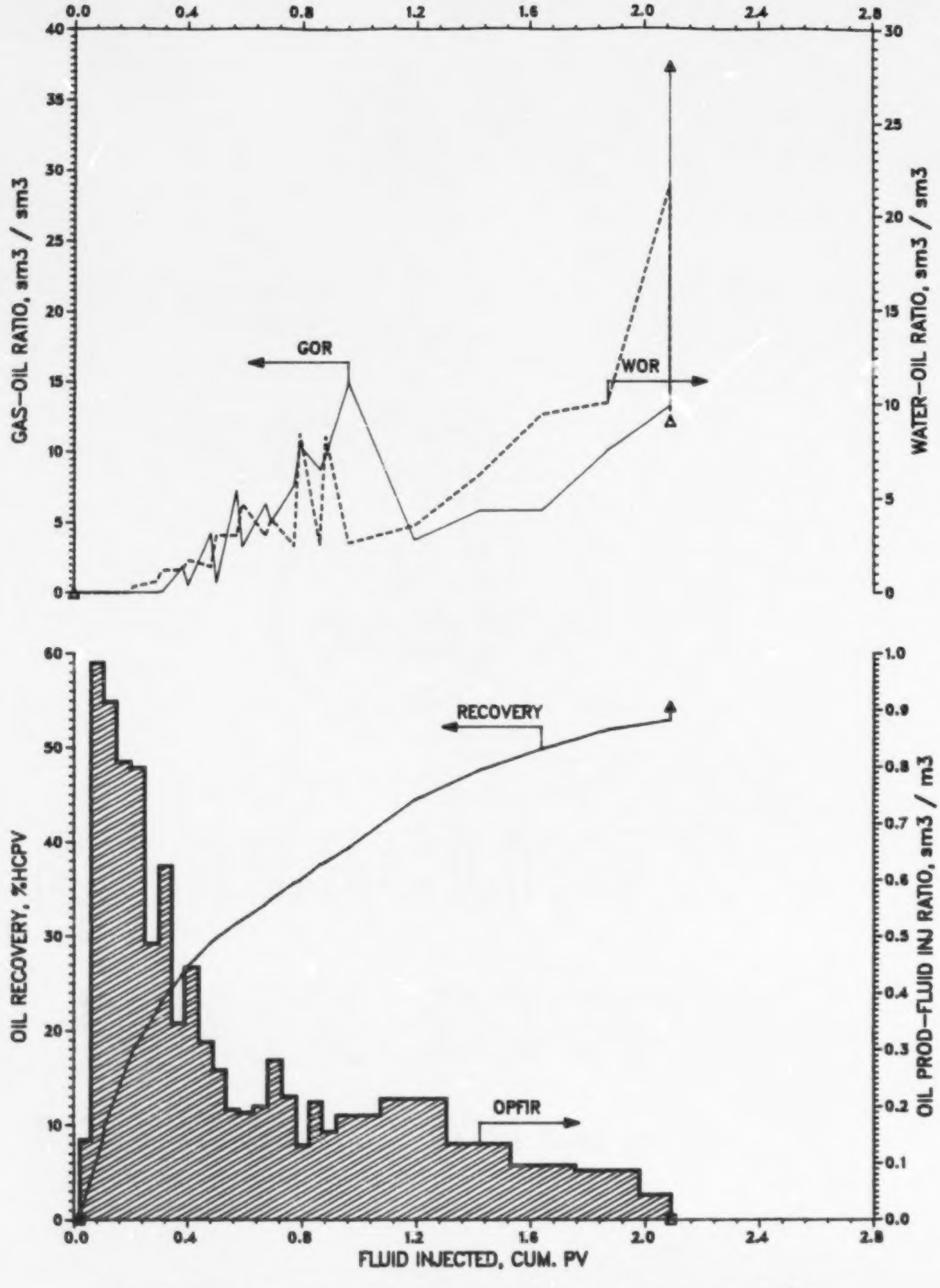
Figure E4 – Production History of Run 1DT10.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.77 %, k = 11.890 darcies, S_o = 94.12 %, S_{wc} = 5.88 %

[0.20 HCPV CO2–N2 @ 1.00 MPa (0.089 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 20.00%

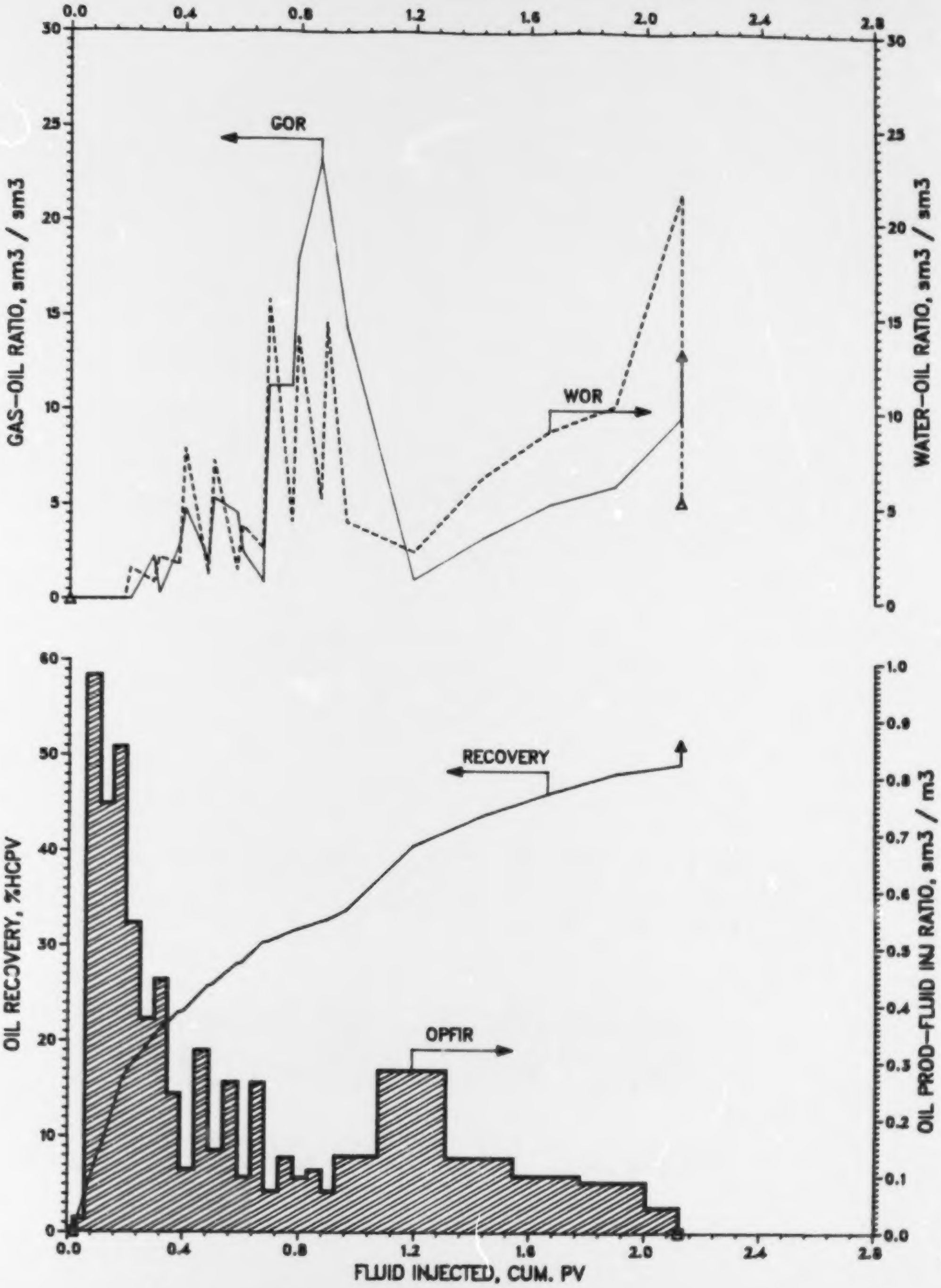
Figure E5 – Production History of Run 1DT11.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.77 %, k = 11.430 darcies, S_o = 95.77 %, S_{wc} = 4.23 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.091 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 25.00%

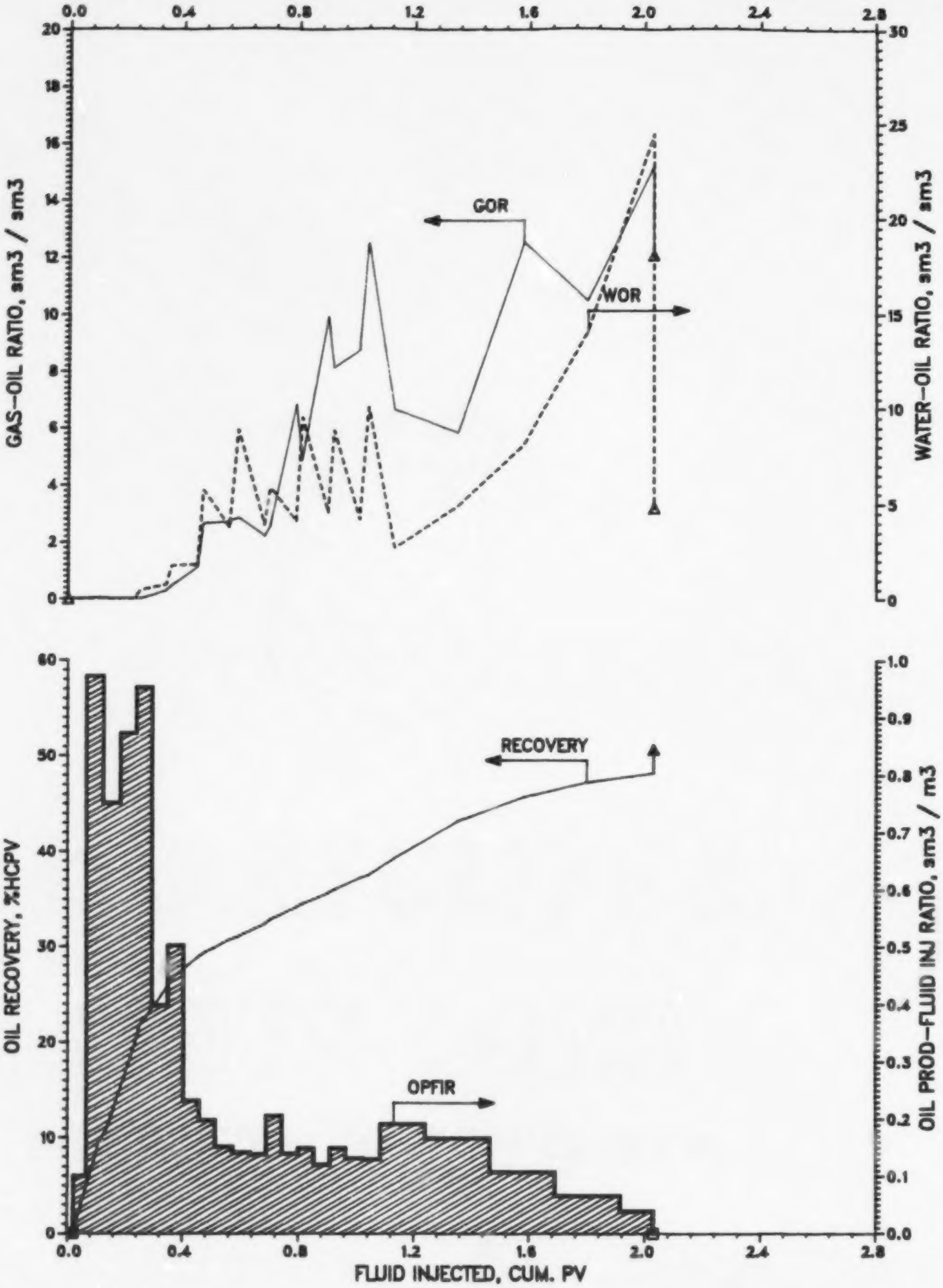
Figure E6 – Production History of Run 1DT12.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.22 %, k = 11.090 darcies, S_o = 96.16 %, S_{wc} = 3.84 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.089 g-mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 30.00%

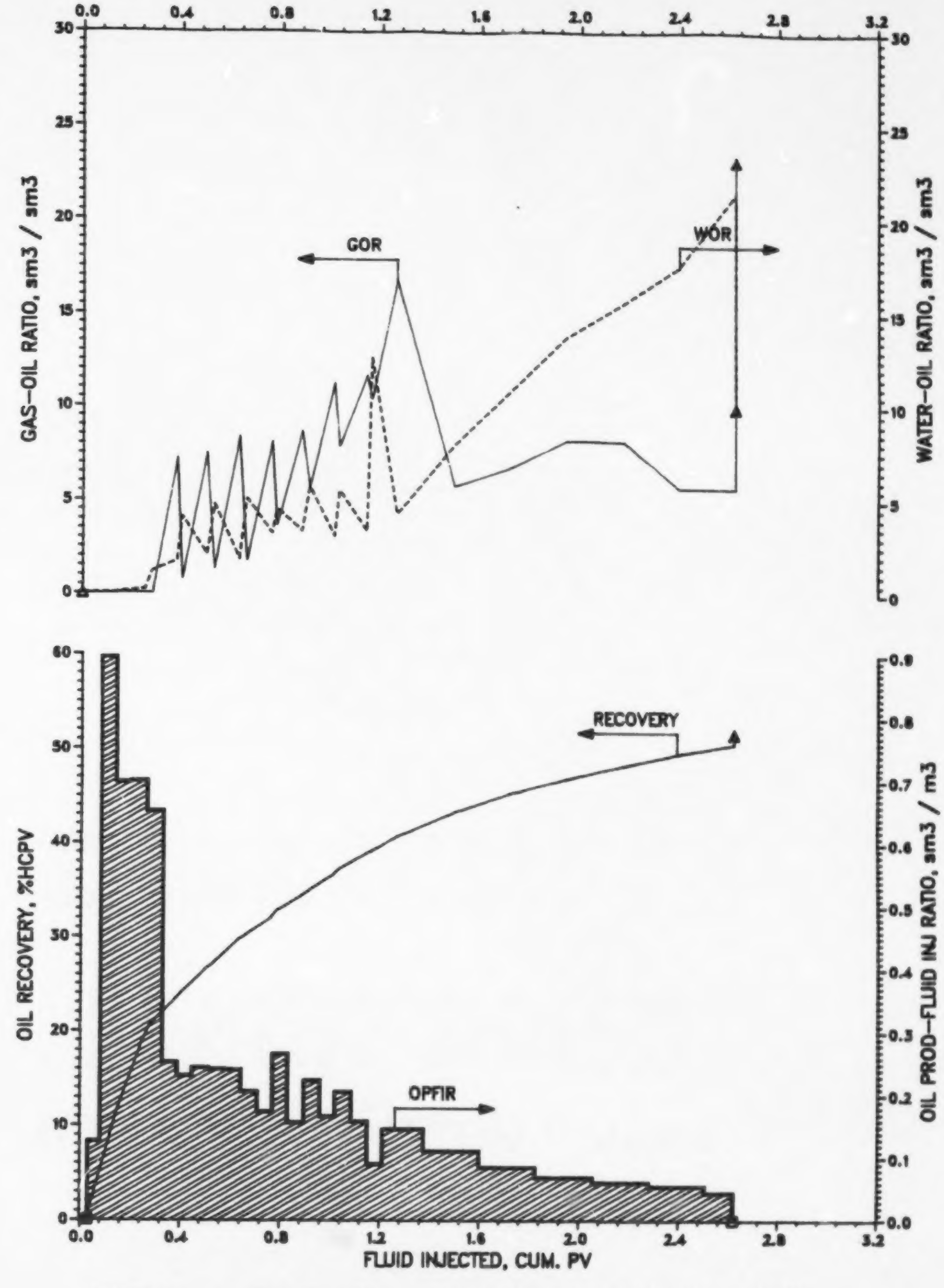
Figure E7 – Production History of Run 1DT13.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.61 %, k = 10.240 darcies, S_o = 95.59 %, S_{wc} = 4.41 %

[0.24 HCPV CO2–N2 @ 1.00 MPa (0.106 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.00%

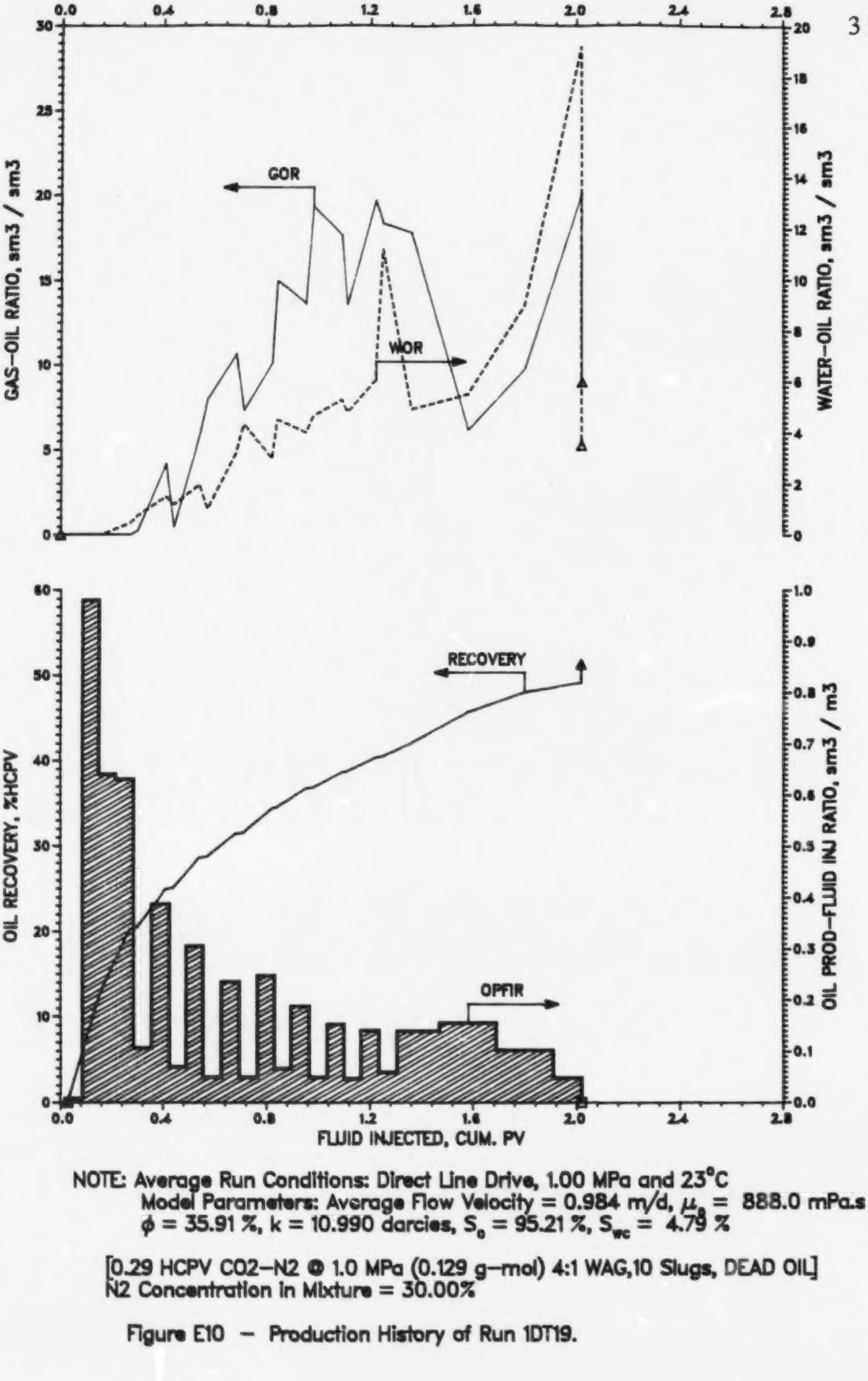
Figure E8 – Production History of Run 1DT17.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.64 %, k = 11.280 darcies, S_o = 94.60 %, S_{wc} = 5.40 %

[0.27 HCPV CO2–N2 @ 1.0 MPa (0.119 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 25.00%

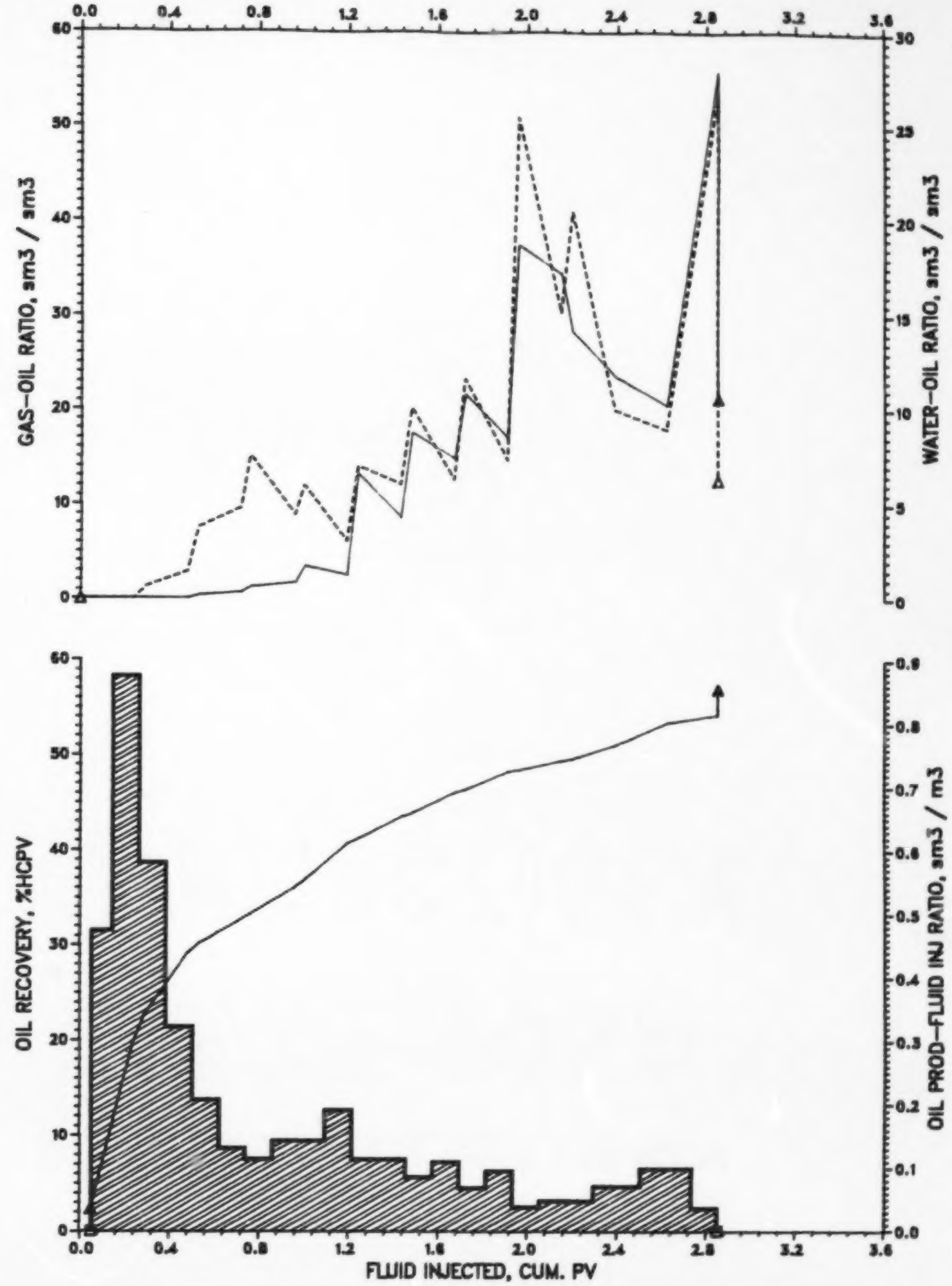
Figure E9 – Production History of Run 1DT18.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.91 %, k = 10.990 darcies, S_o = 95.21 %, S_{wc} = 4.79 %

[0.29 HCPV CO2–N2 @ 1.0 MPa (0.129 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 30.00%

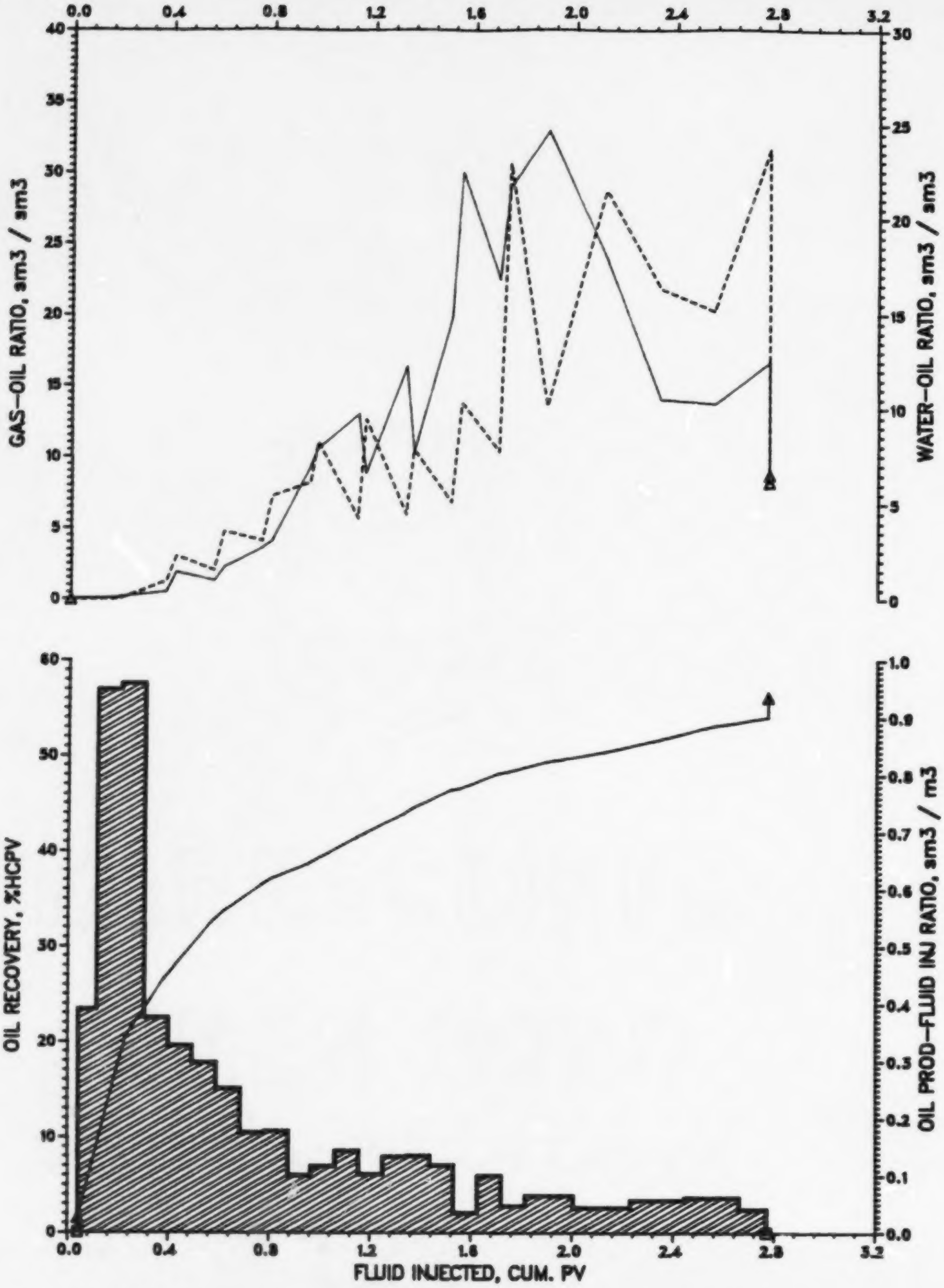
Figure E10 – Production History of Run 1DT19.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.61 %, k = 8.890 darcies, S_o = 95.57 %, S_{wc} = 4.43 %

[0.50 HCPV CO2–N2 @ 1.0 MPa (0.227 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 4.98%

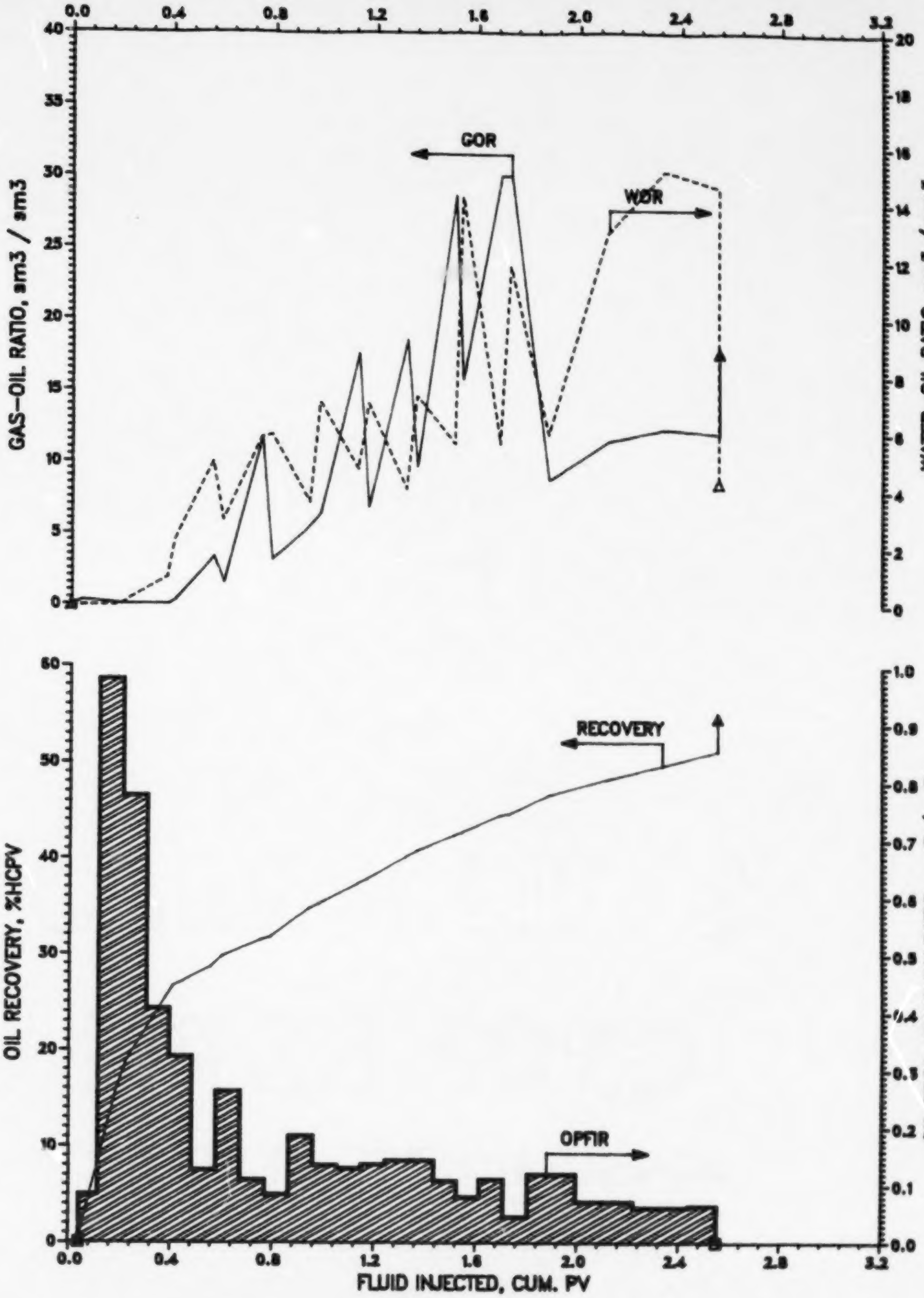
Figure E11 – Production History of Run 1DT20.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.93 %, k = 11.450 darcies, S_o = 94.66 %, S_{wc} = 5.34 %

[0.40 HCPV CO2–N2 @ 1.0 MPa (0.180 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 9.99%

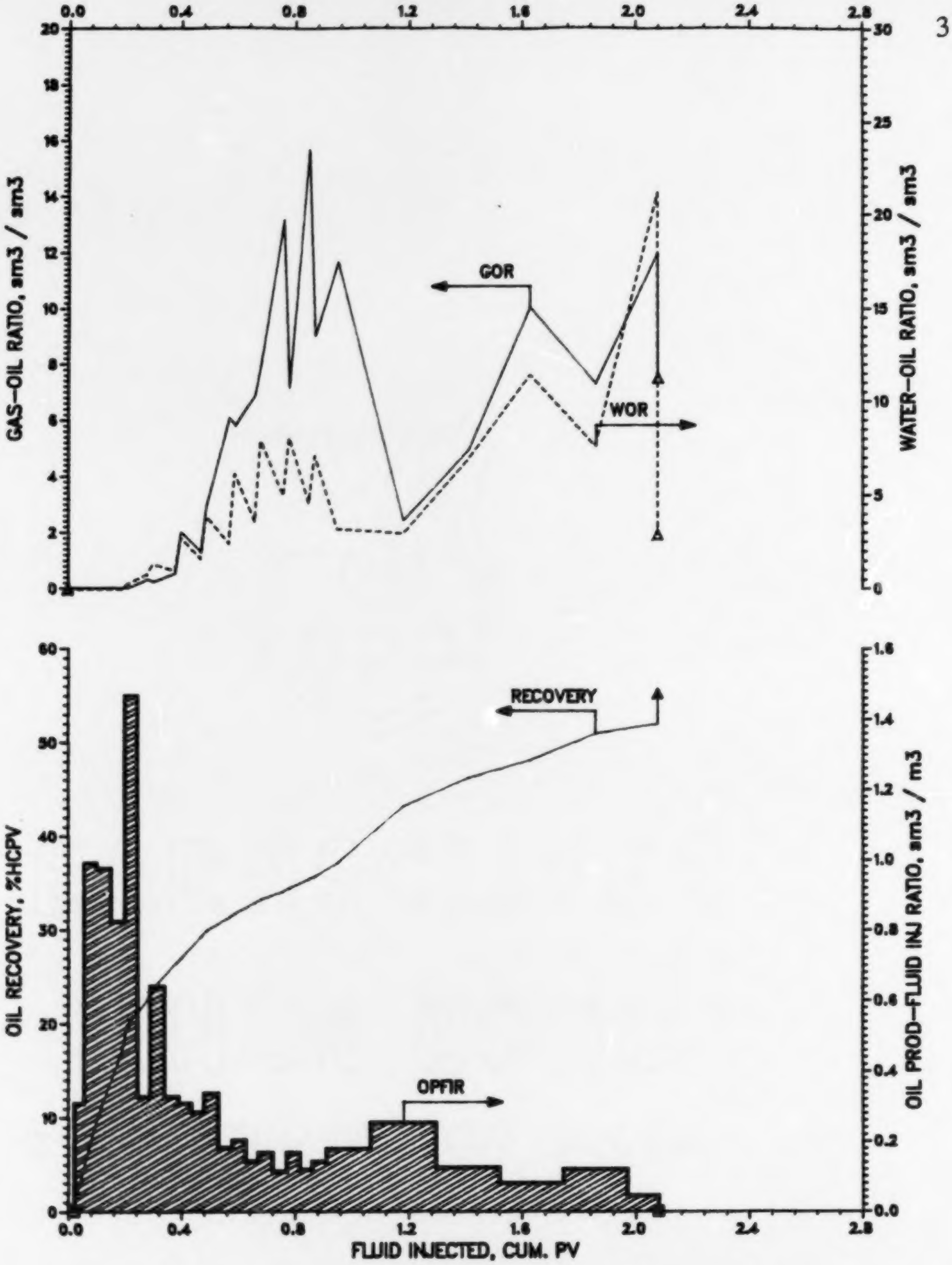
Figure E12 – Production History of Run 1DT21.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.83 %, k = 11.050 darcies, S_o = 94.16 %, S_{wc} = 5.84 %

[0.40 HCPV CO2–N2 @ 1.00 MPa (0.178 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.00%

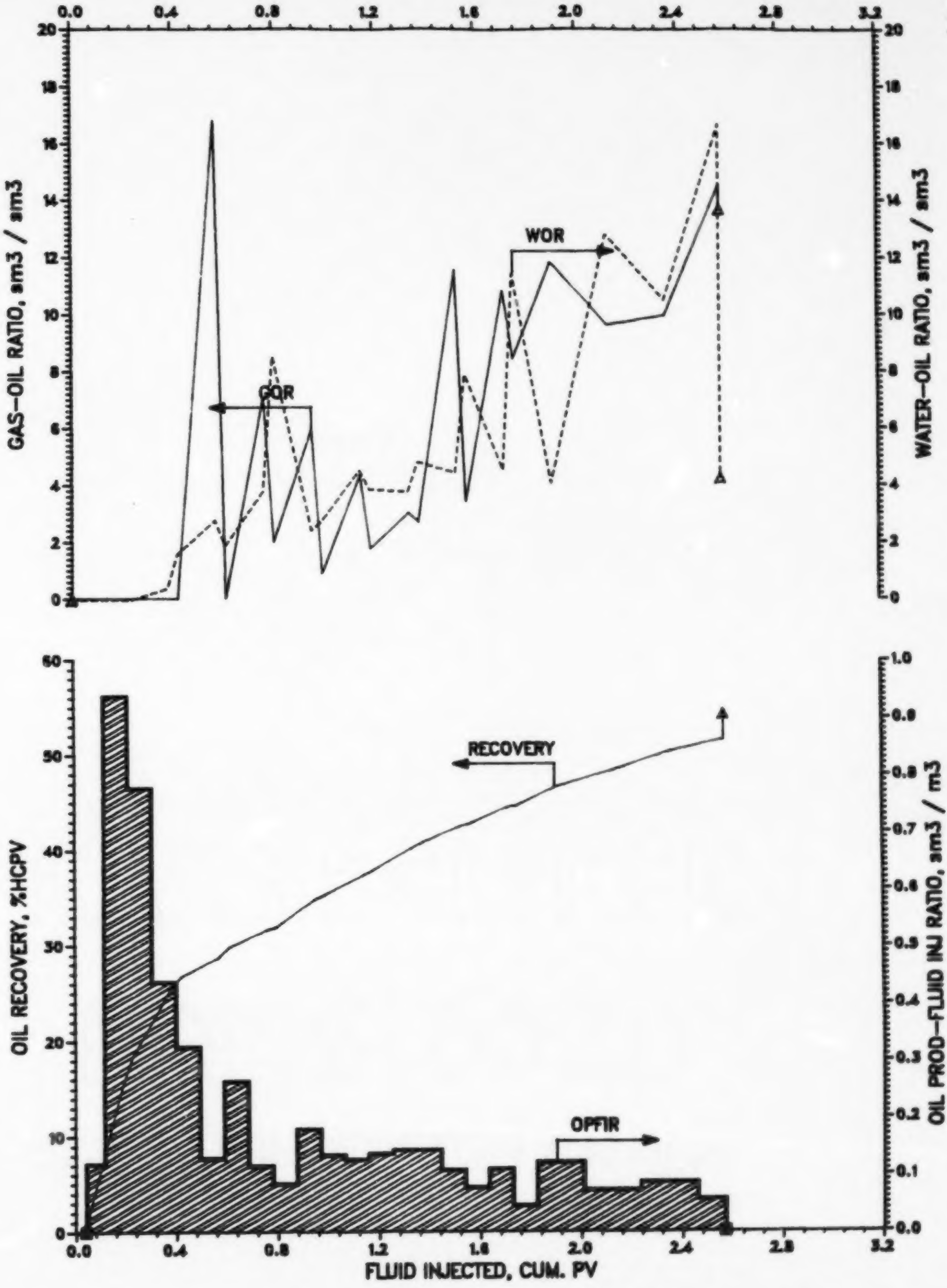
Figure E13 – Production History of Run 1DT22.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.73 %, k = 11.220 darcies, S_o = 94.92 %, S_{wc} = 5.08 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.090 g-mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 9.99%

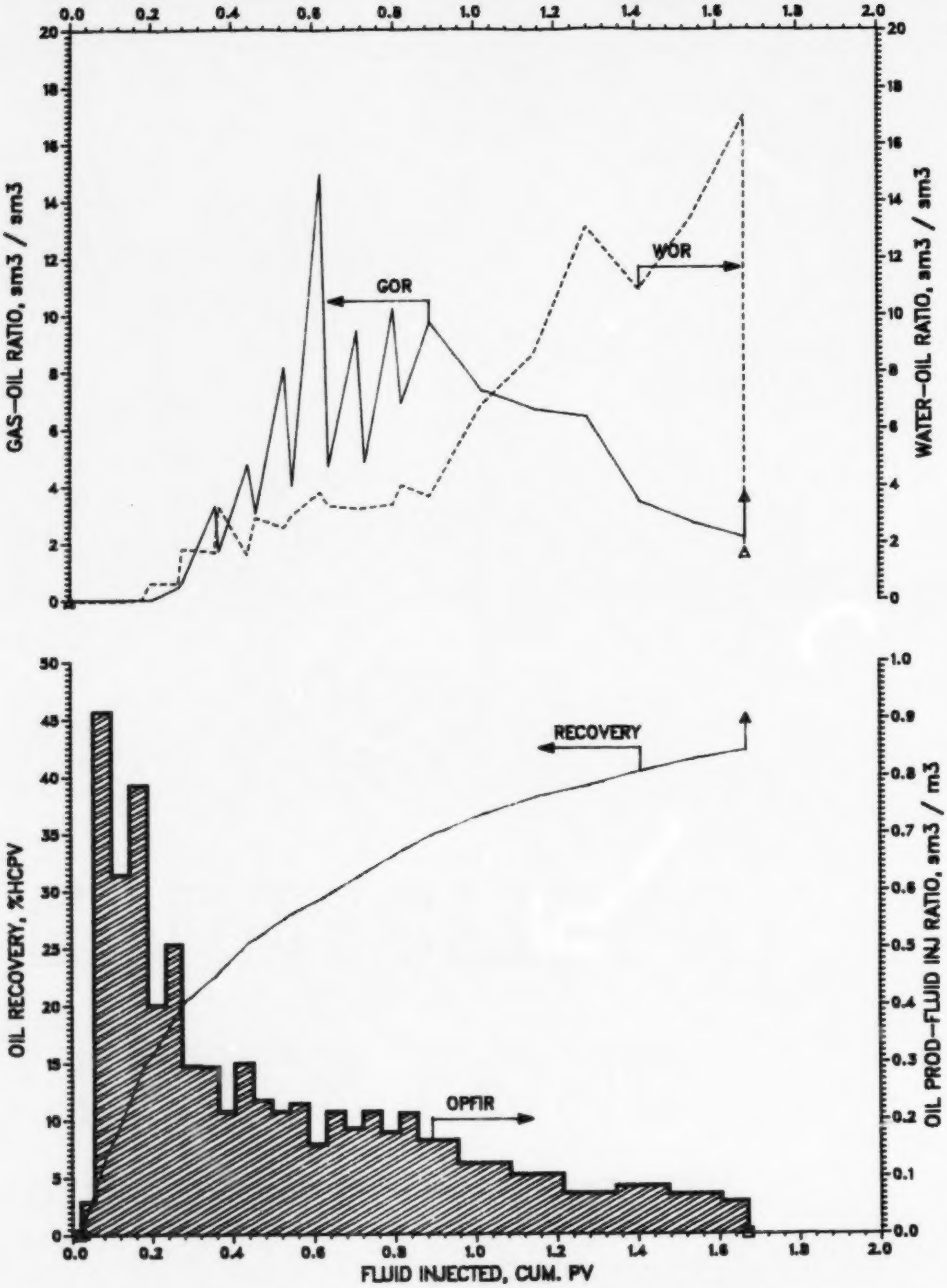
Figure E14 – Production History of Run 1DT23.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.59 %, k = 10.900 darcies, S_o = 94.89 %, S_{wc} = 5.11 %

[0.40 HCPV CO2–N2 @ 1.0 MPa (0.180 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.00%

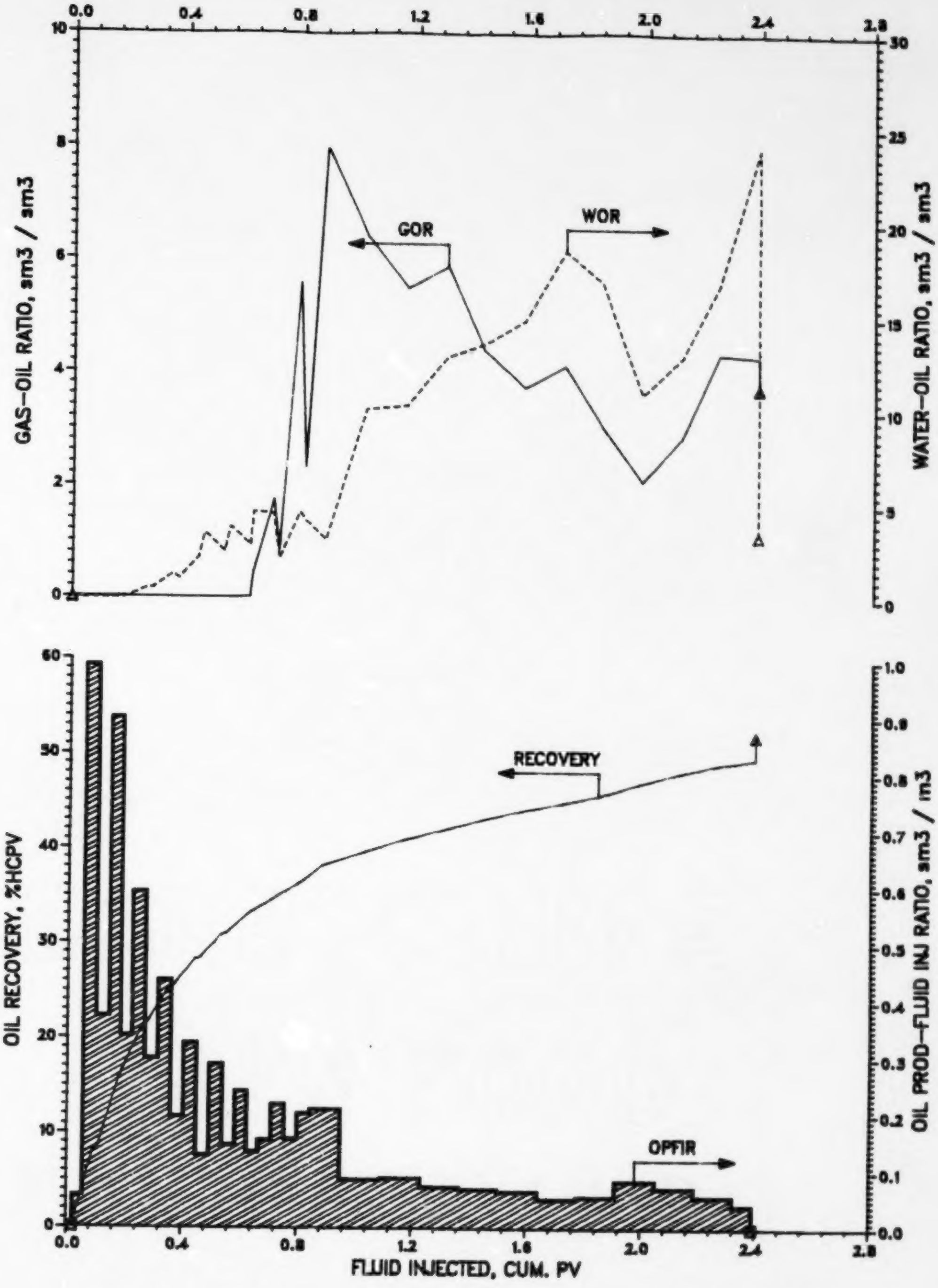
Figure E15 – Production History of Run 1DT24.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 40.44 %, k = 11.790 darcies, S_o = 88.98 %, S_{wc} = 11.02 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.151 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 4.98%

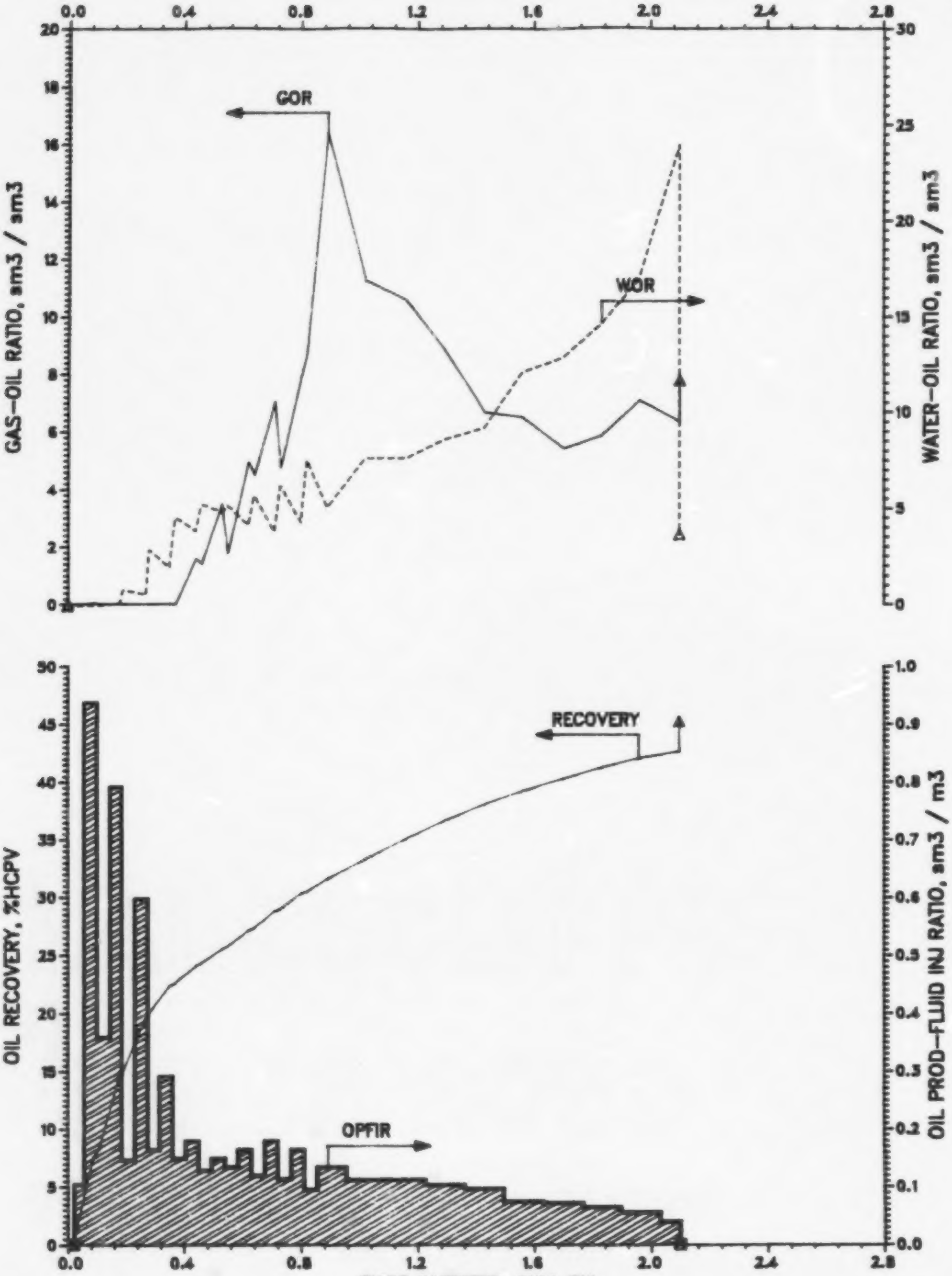
Figure E16 – Production History of Run 2DT7.



NOTE: Average Run Conditions: Quarter of a 5–Spot,1.20 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 37.71 %, k = 11.610 darcies, S_o = 88.11 %, S_{wc} = 11.89 %

[0.20 HCPV CO2–N2 @ 1.2 MPa (0.168 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.00%

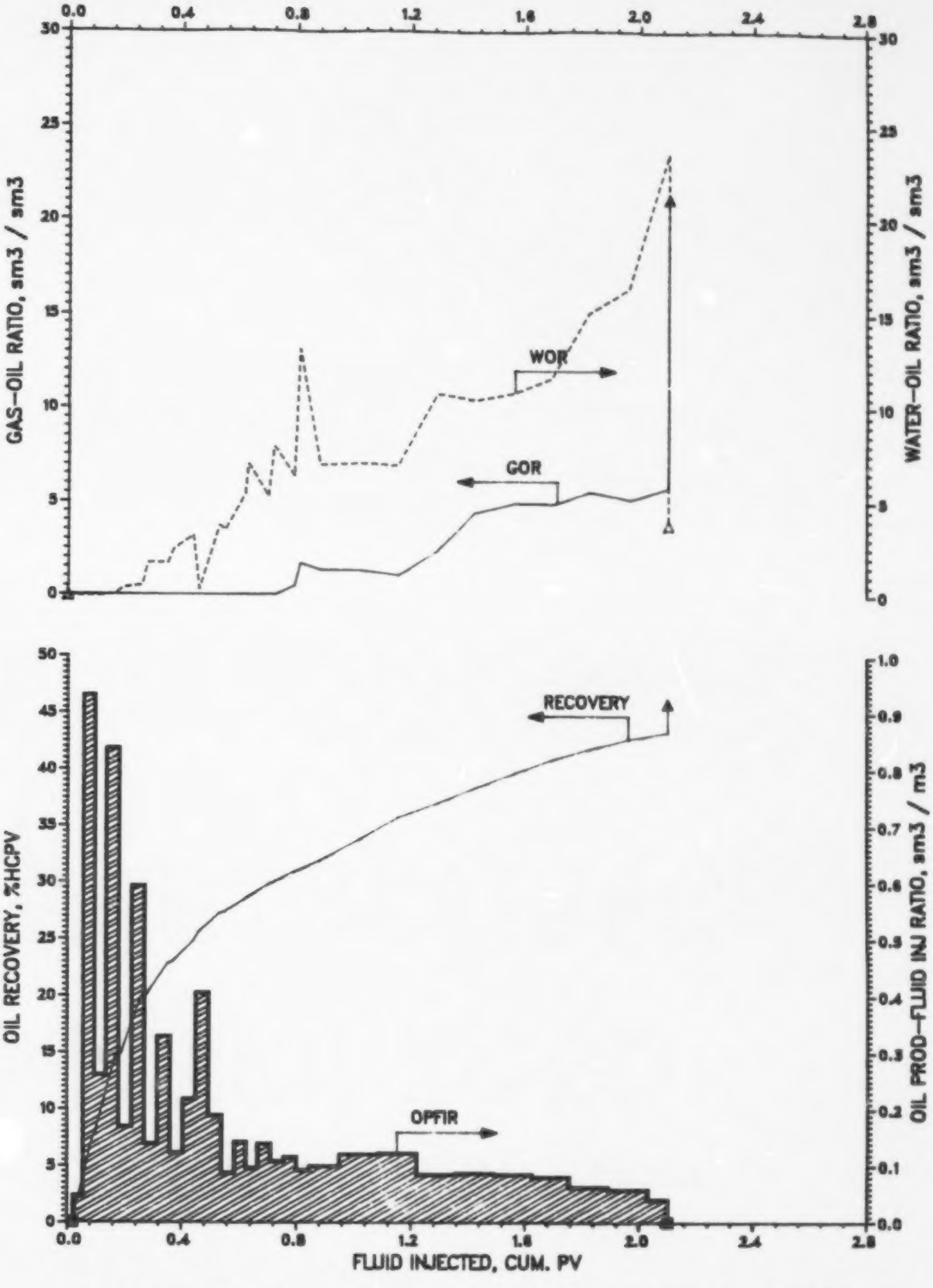
Figure E17 – Production History of Run 2DT8.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.44 MPa and 23°C
Model Parameters: Average Flow Vslocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 38.80 %, k = 11.400 darcies, S_o = 88.60 %, S_{wc} = 11.91 %

[0.20 HCPV CO2–N2 @ 1.44 MPa (0.208 g–mol) 4:1 WAG,10 Slugs,DEAD OIL]
N2 Concentration in Mixture = 30.00%

Figure E19 – Production History of Run 2DT10.



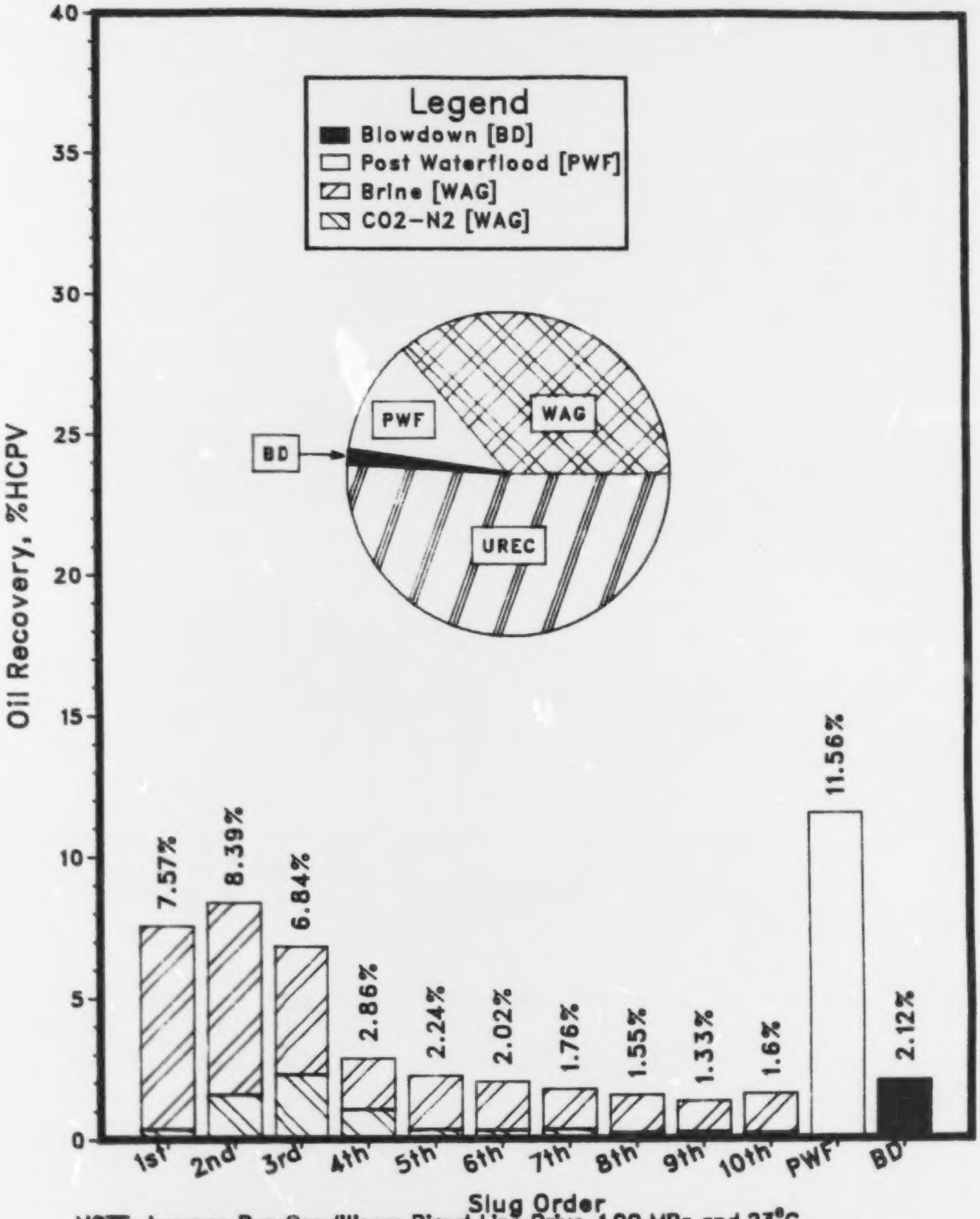
NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.25 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 38.60 %, k = 12.960 darcies, S_o = 87.04 %, S_{wc} = 11.17 %

[0.20 HCPV CO2–N2 @ 1.25 MPa (0.176 g–mol) 4:1 WAG,10 Slugs,DEAD OIL]
N2 Concentration in Mixture = 20.00%

Figure E18 – Production History of Run 2DT9.

APPENDIX F

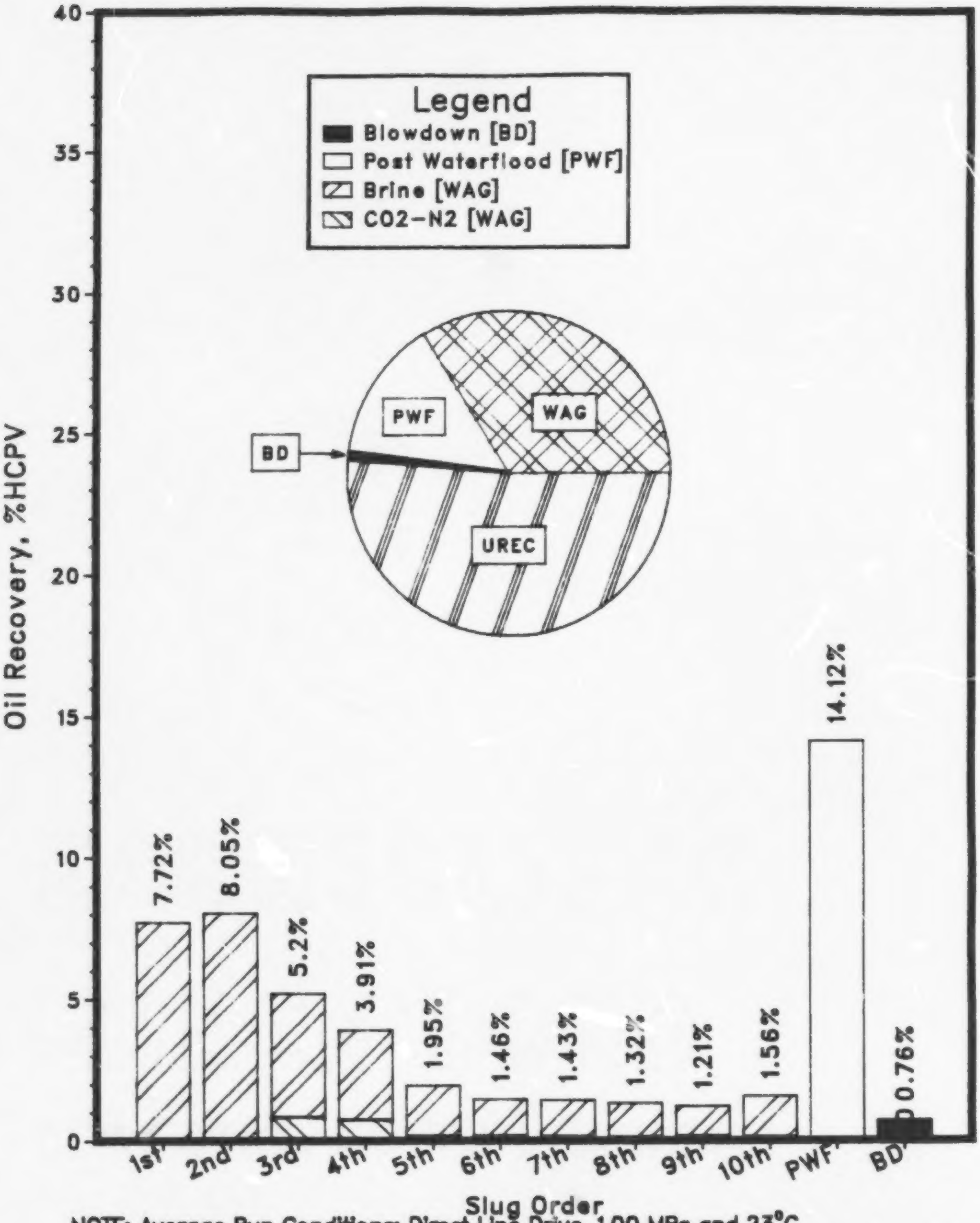
Oil Recovery Distributions of All Experiments Conducted



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1058.0 mPa.s
ϕ = 35.73 %, k = 11.310 darcies, S_o = 94.98 %, S_{wc} = 5.02 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.092 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 4.98%
Total Oil Recovery = 49.8 %

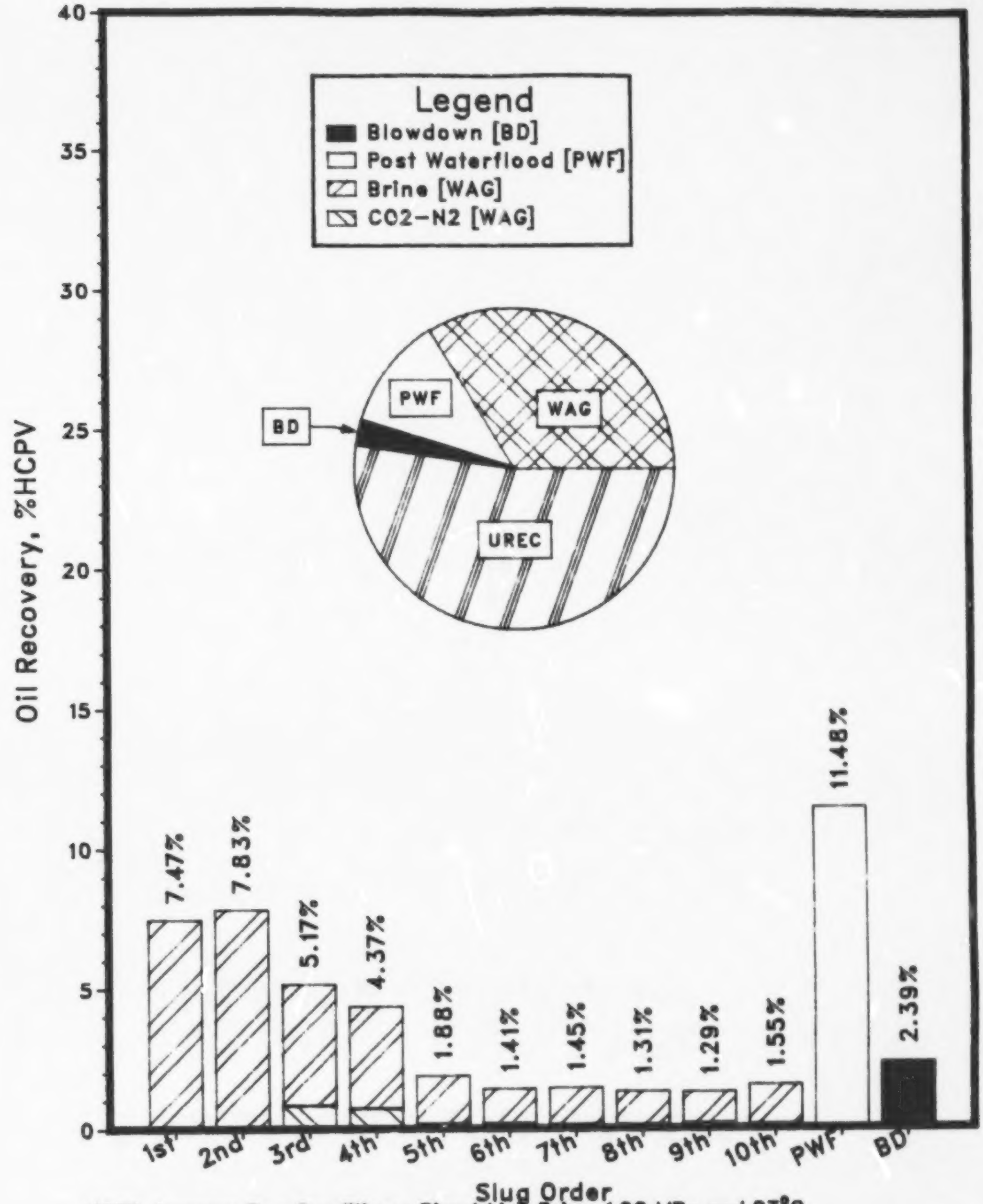
Figure F1 – Oil Recovery Distribution of Run 1DT1.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1058.0 mPa.s
ϕ = 35.82 %, k = 10.700 darcies, S_o = 94.86 %, S_{wc} = 5.14 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.091 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 9.99%
Total Oil Recovery = 48.7%

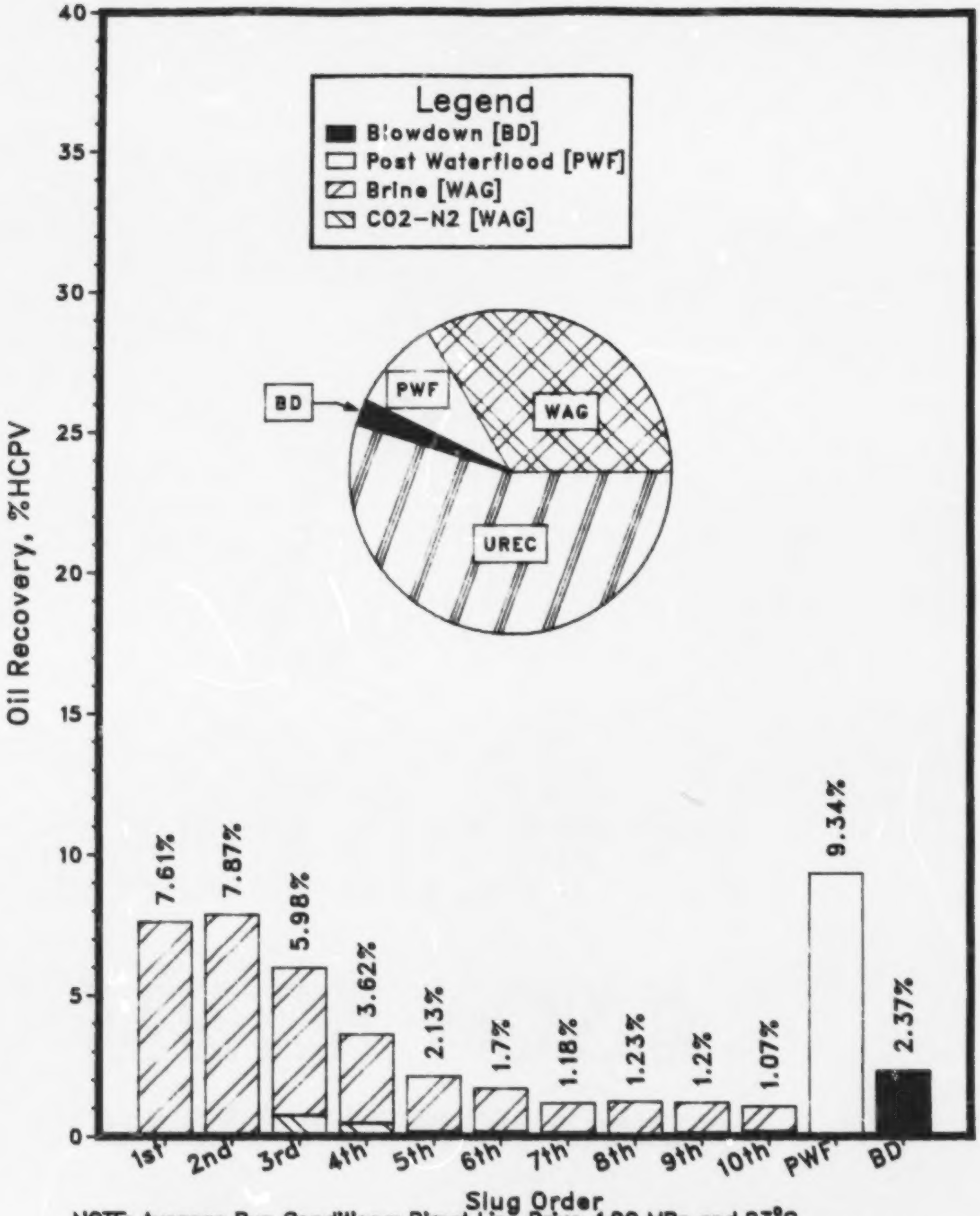
Figure F2 — Oil Recovery Distribution of Run 1DT2.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1058.0 mPa.s
ϕ = 36.06 %, k = 10.510 darcies, S_o = 92.44 %, S_{wc} = 7.56 %

[0.20 HCPV CO2-N2 @ 1.0 MPa (0.091 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.00%
Total Oil Recovery = 47.6%

Figure F3 — Oil Recovery Distribution of Run 1DT3.



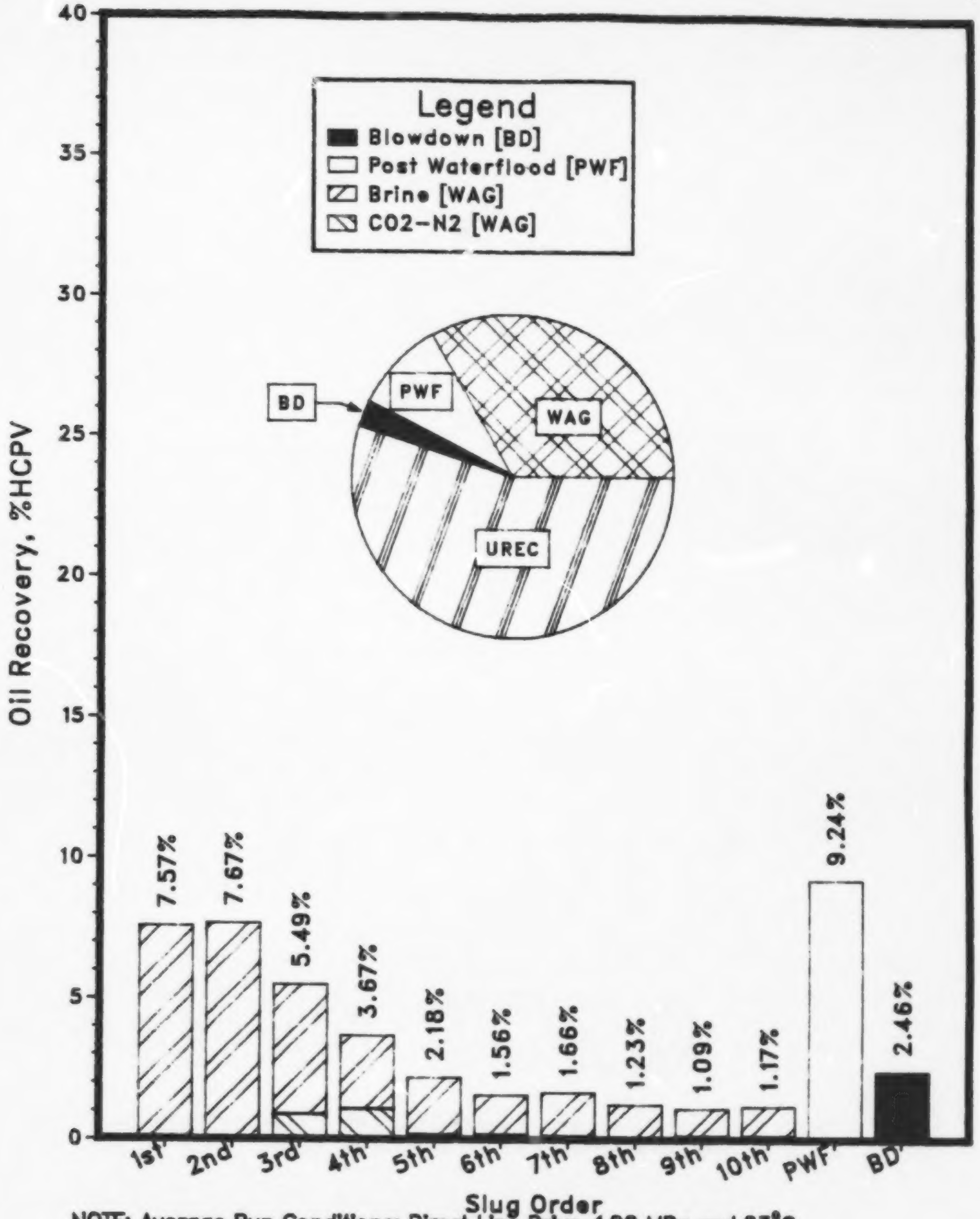
NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C

Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1058.0 mPa.s

ϕ = 35.59 %, k = 10.770 darcies, S_o = 95.53 %, S_{wc} = 4.47 %

[0.20 HCPV CO2-N2 @ 1.0 MPa (0.090 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 20.00%
Total Oil Recovery = 45.3%

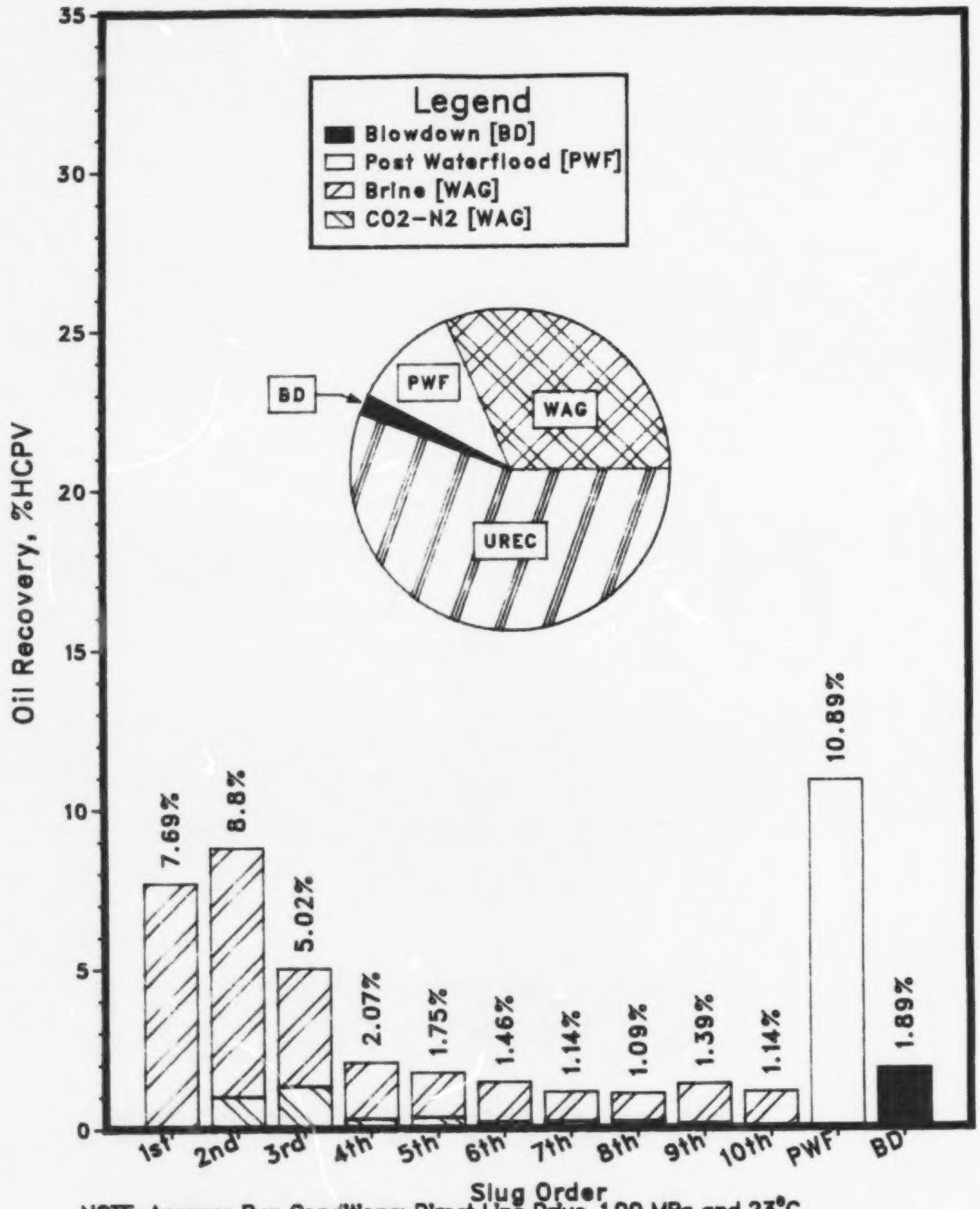
Figure F4 – Oil Recovery Distribution of Run 1DT4.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1058.0 mPa.s
ϕ = 35.16 %, k = 10.630 darcies, S_o = 95.28 %, S_{wc} = 4.72 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.090 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 25.00%
Total Oil Recovery = 45.0%

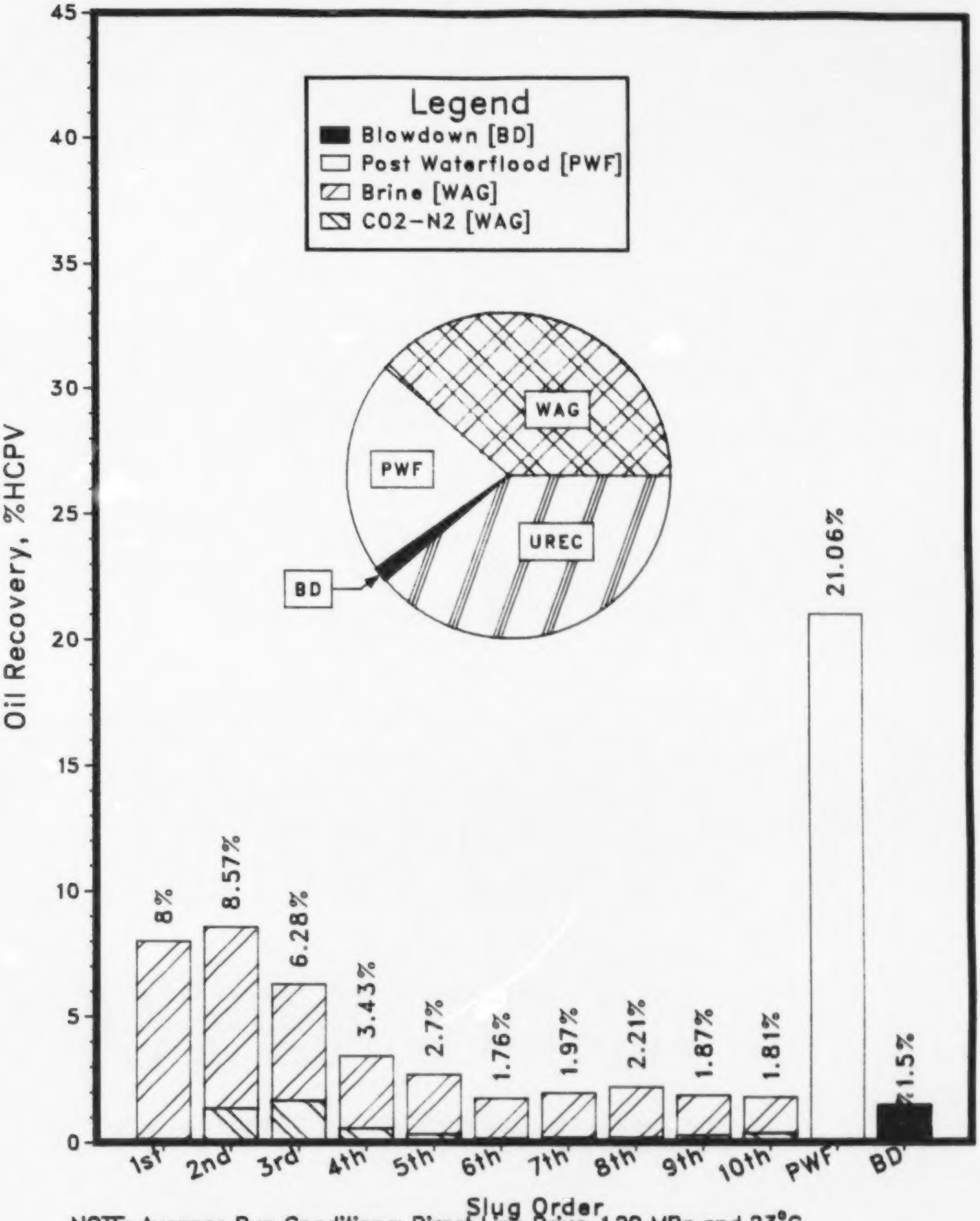
Figure F5 – Oil Recovery Distribution of Run 1DT5.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 1058.0 mPa.s
ϕ = 35.70 %, k = 10.730 darcies, S_o = 95.54 %, S_{wc} = 4.46 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.090 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 30.00%
Total Oil Recovery = 44.3%

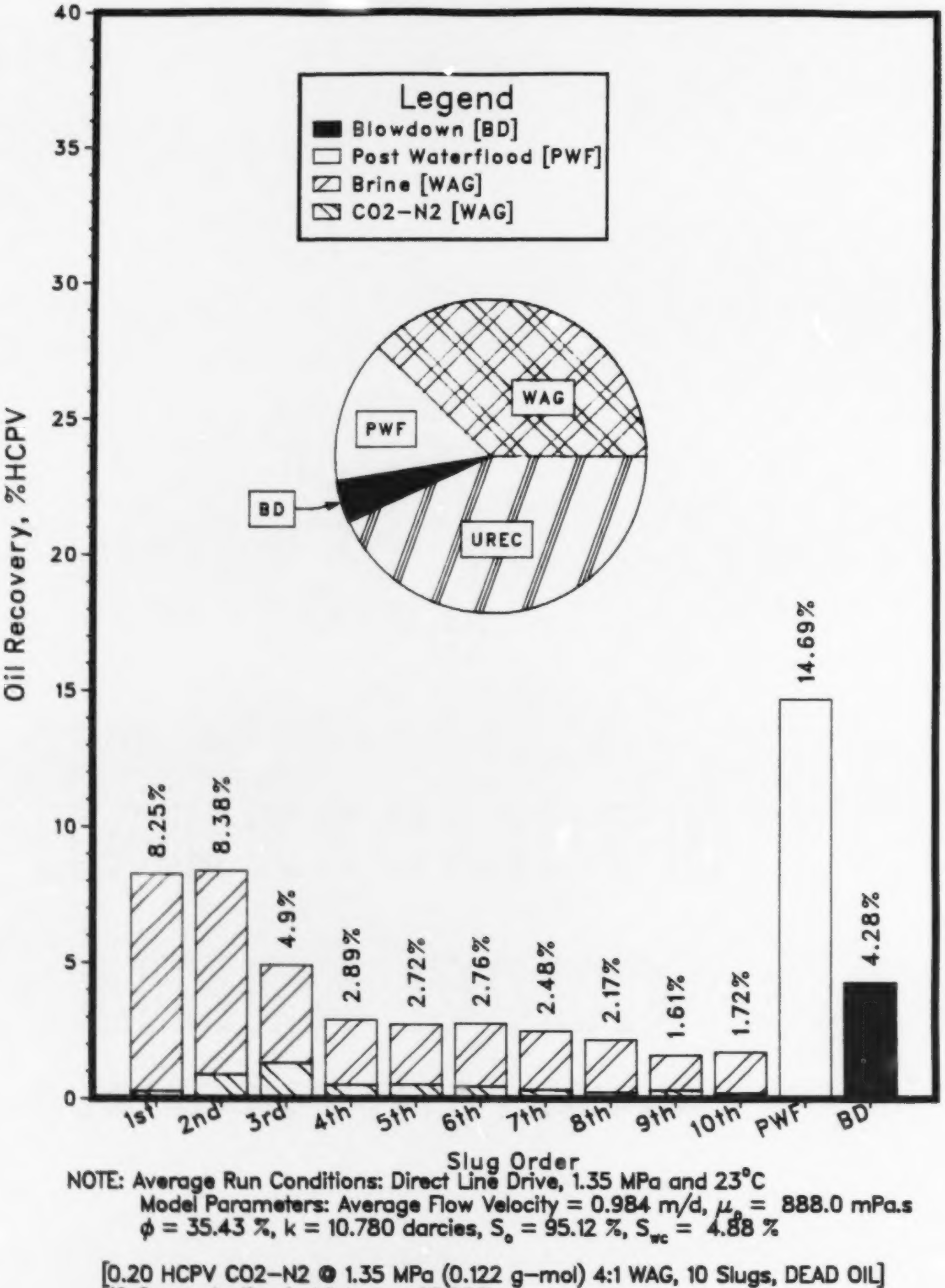
Figure F6 — Oil Recovery Distribution of Run 1DT6.



NOTE: Average Run Conditions: Direct Line Drive, 1.20 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.90 %, k = 11.690 darcies, S_o = 95.51 %, S_{wc} = 4.49 %

[0.20 HCPV CO2–N2 @ 1.2 MPa (0.111 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.00%
Total Oil Recovery = 61.2%

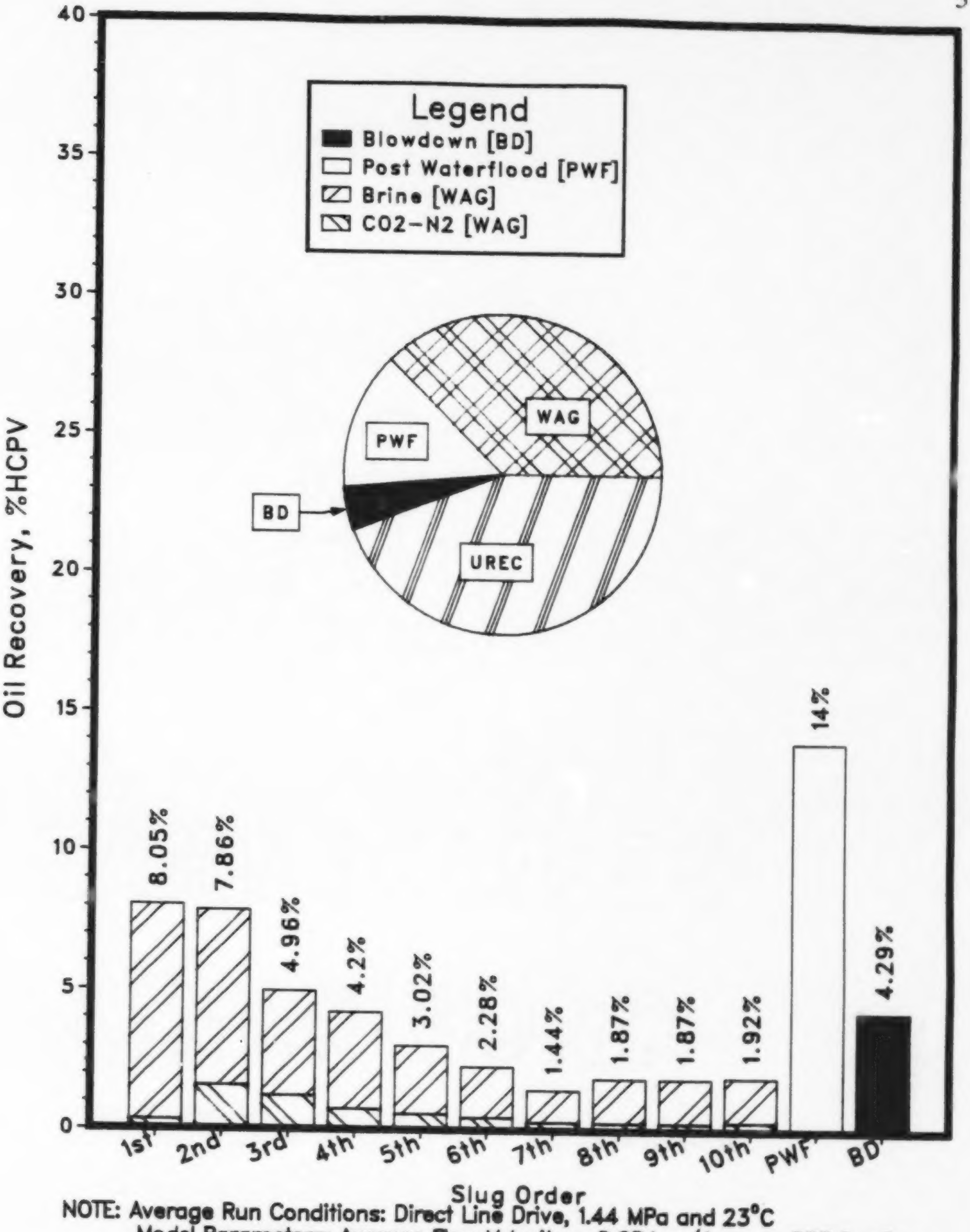
Figure F7 — Oil Recovery Distribution of Run 1DT14.



NOTE: Average Run Conditions: Direct Line Drive, 1.35 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.43 %, k = 10.780 darcies, S_o = 95.12 %, S_{wc} = 4.88 %

[0.20 HCPV CO2–N2 @ 1.35 MPa (0.122 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 25.00%
Total Oil Recovery = 56.9%

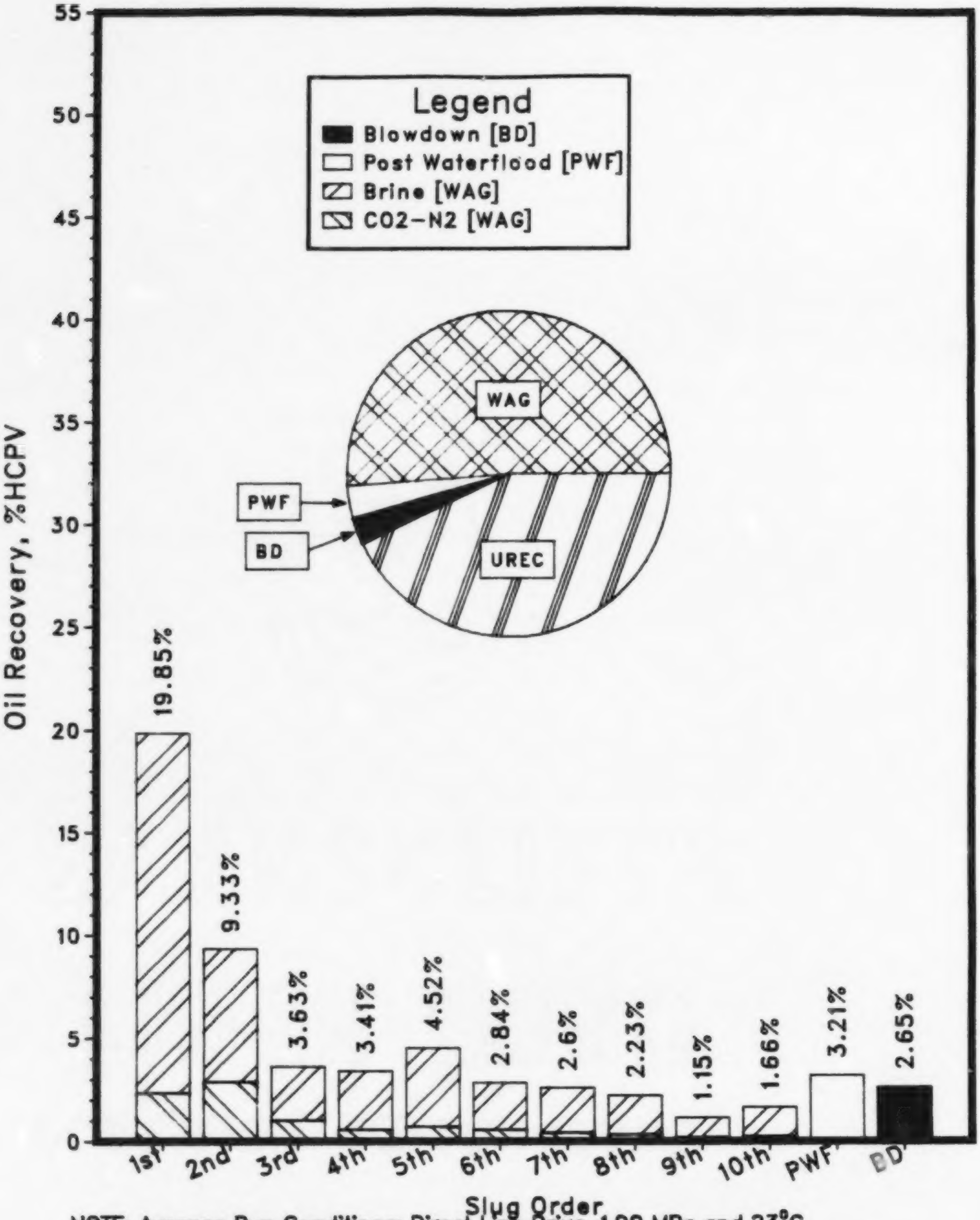
Figure F8 – Oil Recovery Distribution of Run 1DT15.



NOTE: Average Run Conditions: Direct Line Drive, 1.44 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.51 %, k = 10.020 darcies, S_o = 95.12 %, S_{wc} = 4.88 %

[0.20 HCPV CO2–N2 @ 1.44 MPa (0.130 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 30.00%
Total Oil Recovery = 55.8%

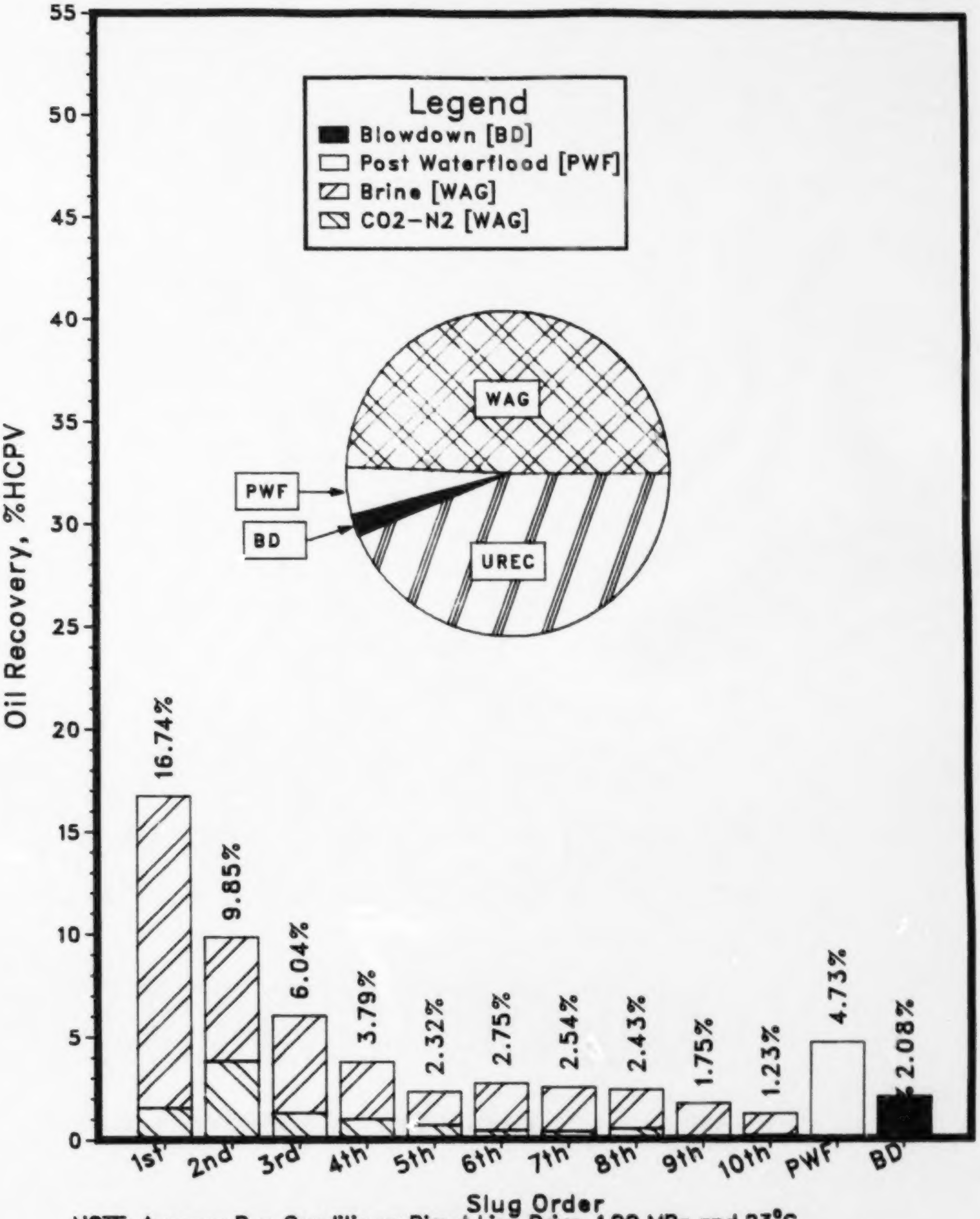
Figure F9 – Oil Recovery Distribution of Run 1DT16.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.61 %, k = 10.890 darcies, S_o = 95.57 %, S_{wc} = 4.43 %

[0.50 HCPV CO2–N2 @ 1.0 MPa (0.227 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 4.98%.
Total Oil Recovery = 57.1%

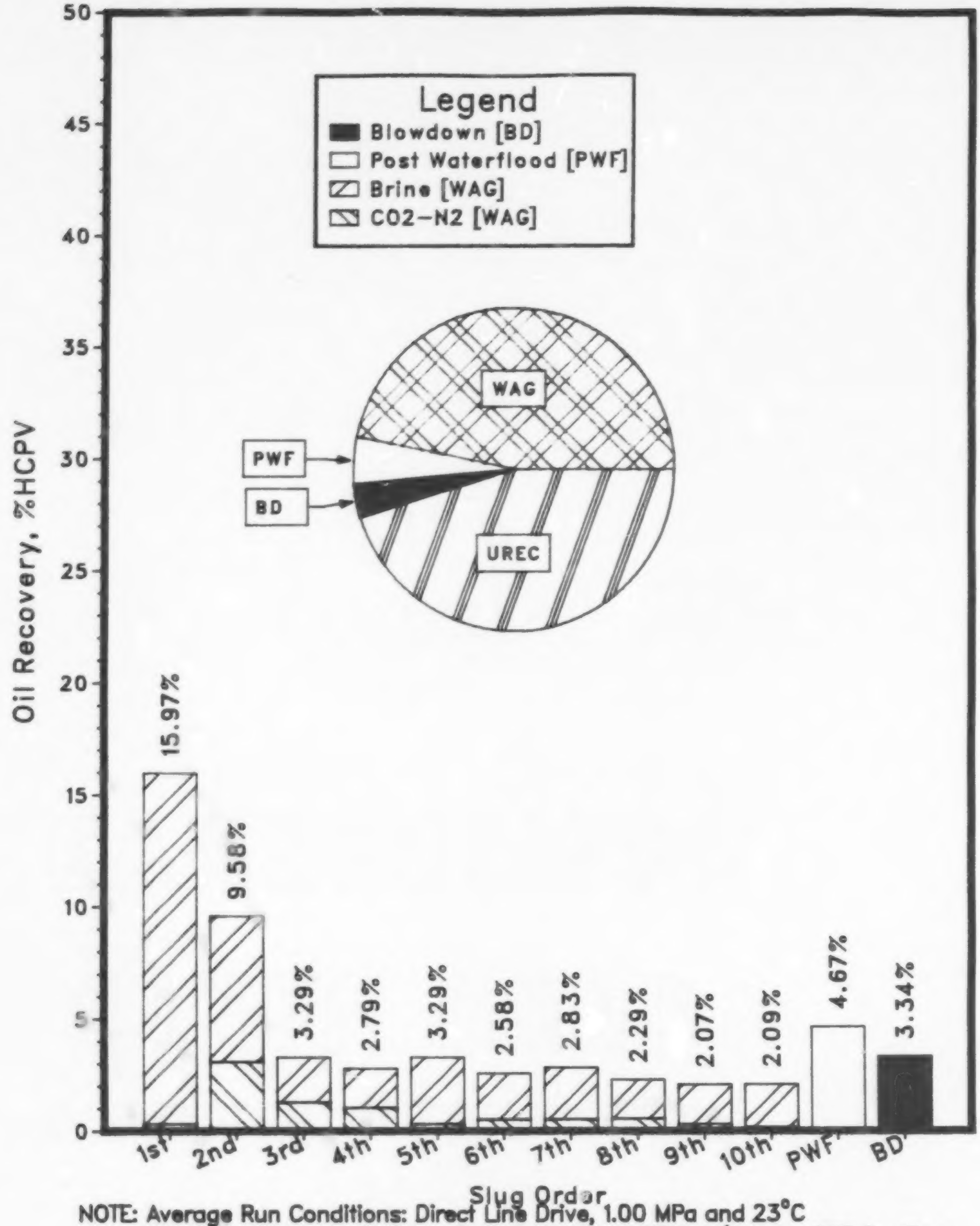
Figure F10 – Oil Recovery Distribution of Run 1DT20.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.93 %, k = 11.450 darcies, S_o = 94.66 %, S_{wc} = 5.34 %

[0.40 HCPV CO2–N2 @ 1.0 MPa (0.180 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 9.99%.
Total Oil Recovery = 56.3%

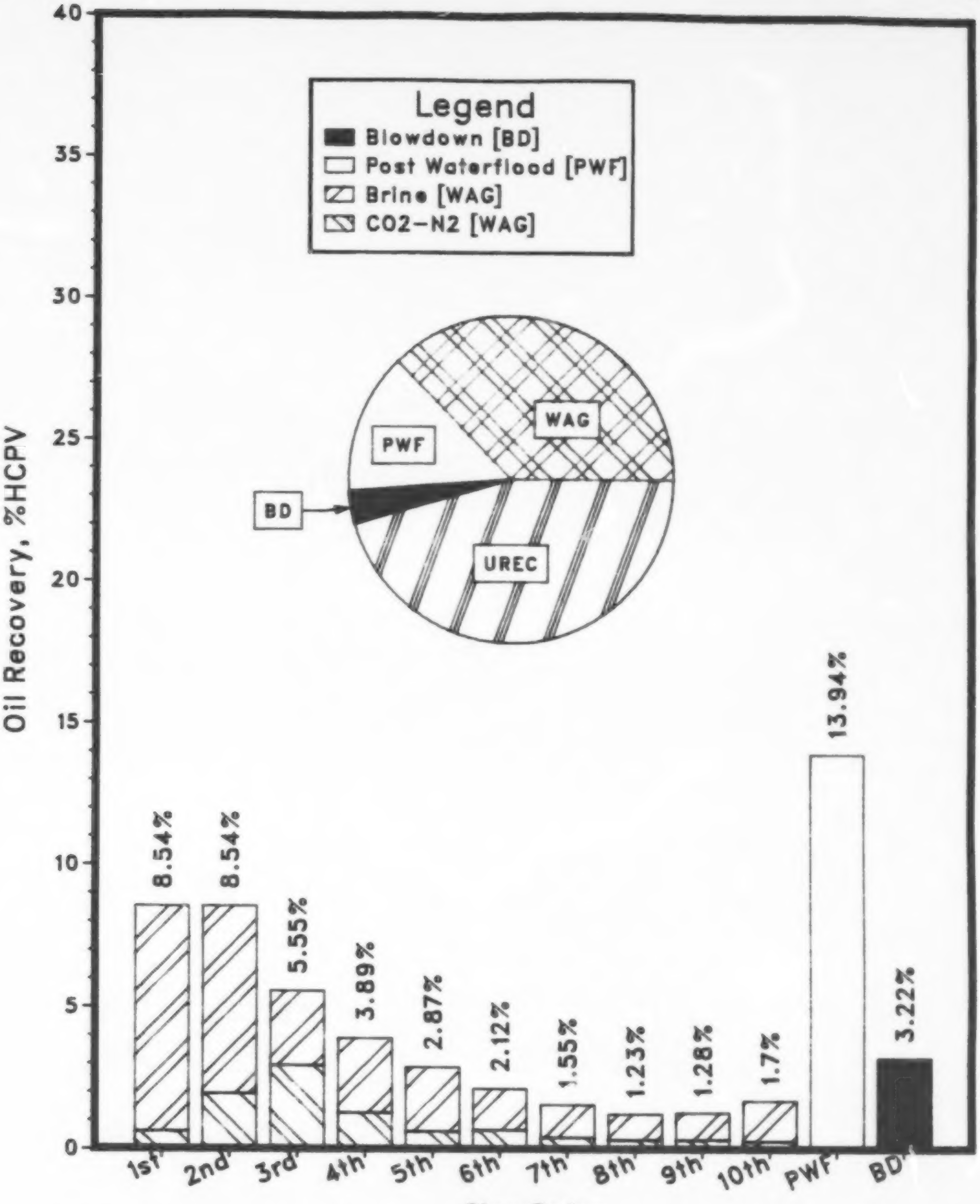
Figure F11 — Oil Recovery Distribution of Run 1DT21.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.83 %, k = 11.050 darcies, S_o = 94.14 %, S_{wc} = 5.86 %

[0.40 HCPV CO2–N2 @ 1.0 MPa (0.178 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.00%
Total Oil Recovery = 54.8%

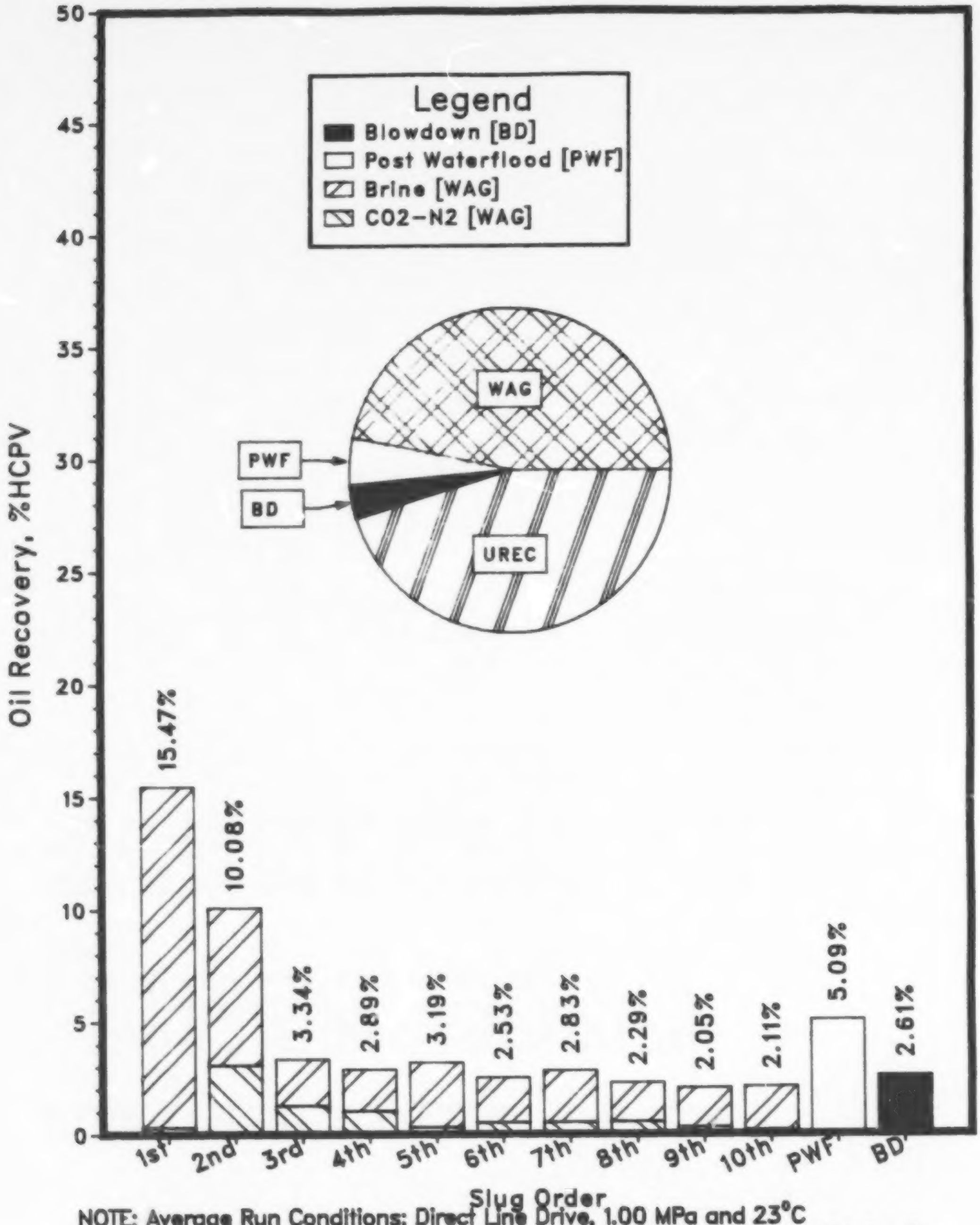
Figure F12 – Oil Recovery Distribution of Run 1DT22.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.73 %, k = 11.220 darcies, S_o = 94.92 %, S_{wc} = 5.08 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.090 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 9.99%
Total Oil Recovery = 54.4%

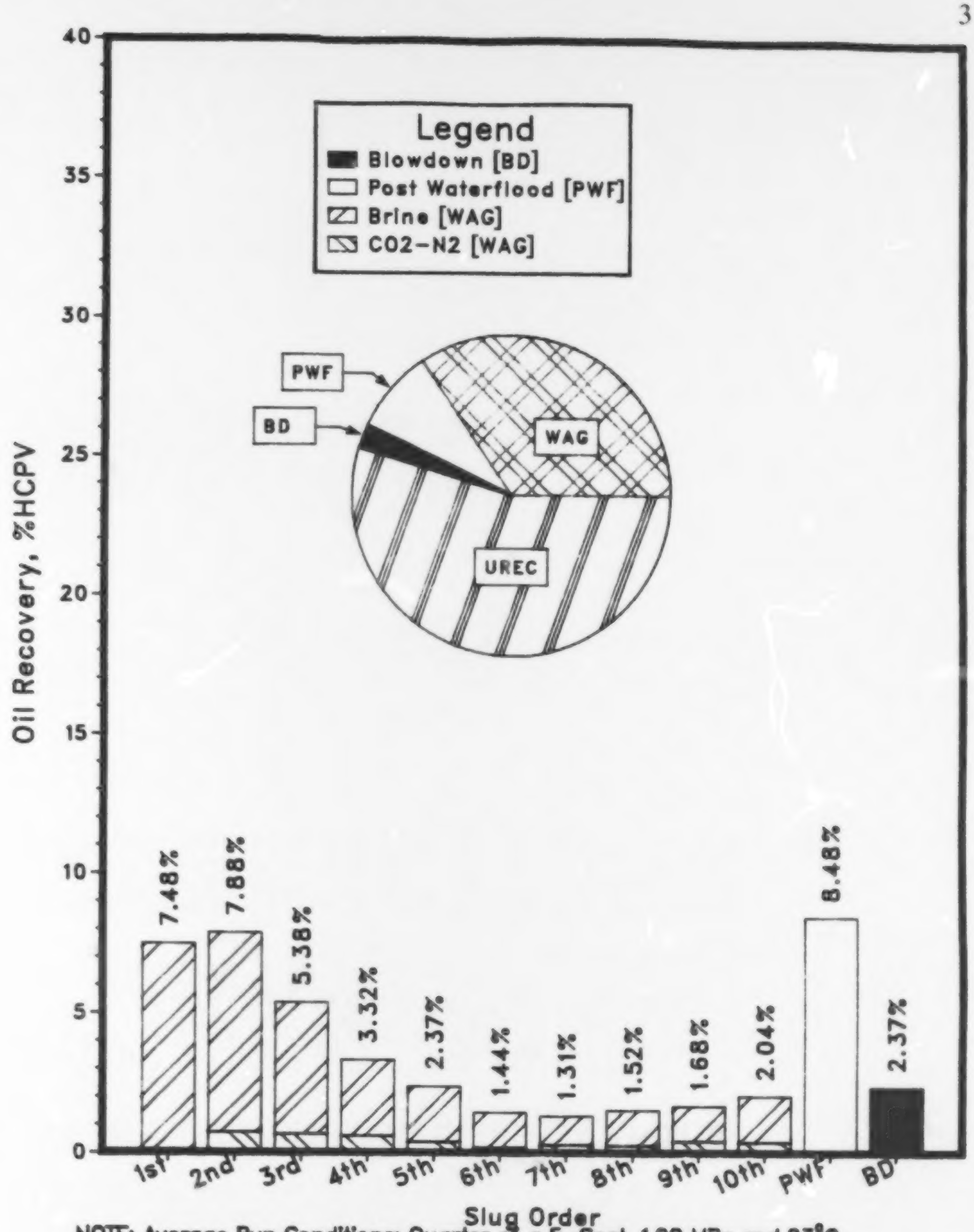
Figure F13 — Oil Recovery Distribution of Run 1DT23.



NOTE: Average Run Conditions: Direct Line Drive, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 0.984 m/d, μ_o = 888.0 mPa.s
ϕ = 35.59 %, k = 10.090 darcies, S_o = 94.89 %, S_{wc} = 5.11 %

[0.40 HCPV CO2–N2 @ 1.0 MPa (0.178 g-mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.00%
Total Oil Recovery = 54.5%

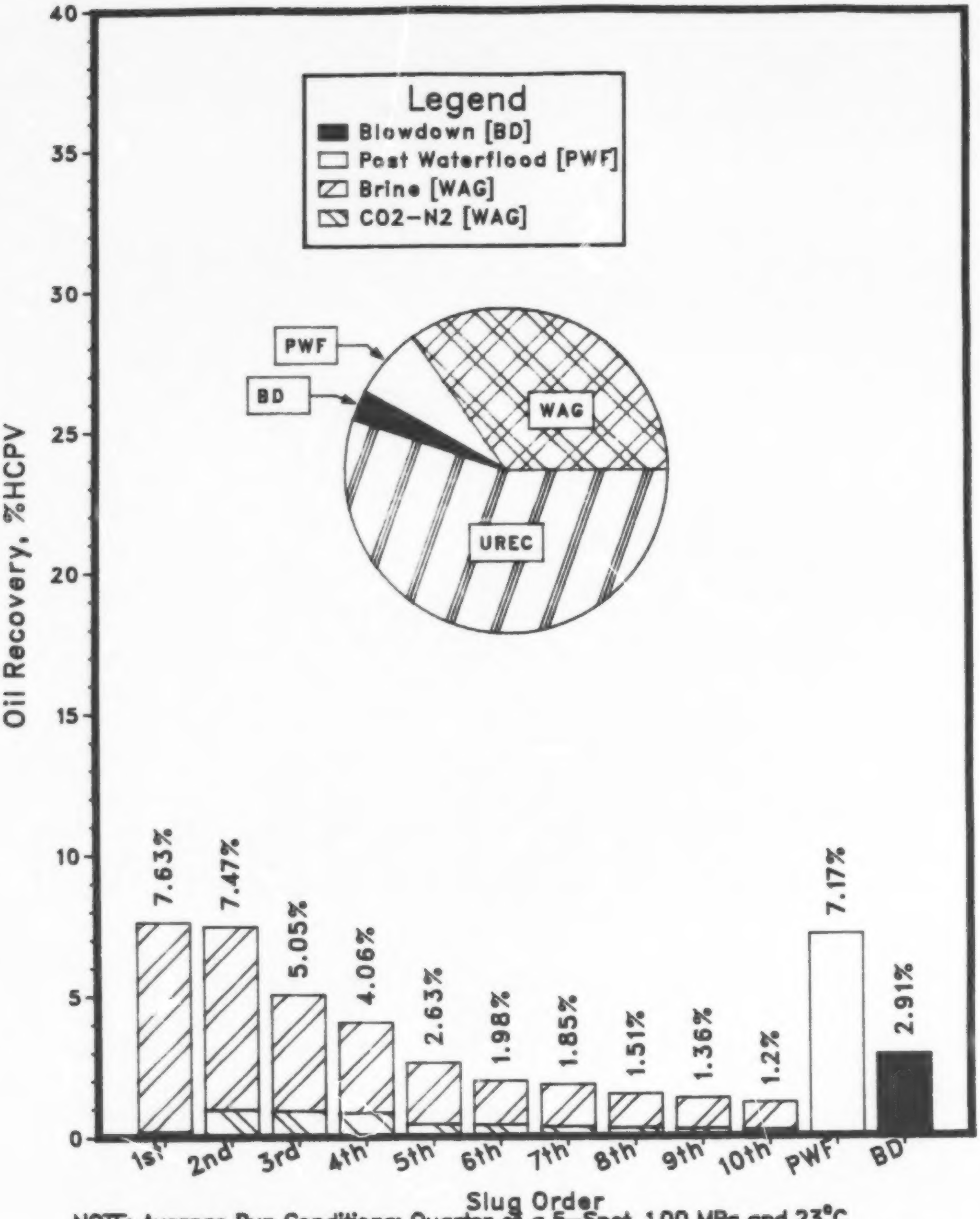
Figure F14 – Oil Recovery Distribution of Run 1DT24.



NOTE: Average Run Conditions: Quarter of a 5-Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 40.77 %, k = 11.140 darcies, S_o = 88.82 %, S_{wc} = 11.18 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.152 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 4.98%
Total Oil Recovery = 45.3%

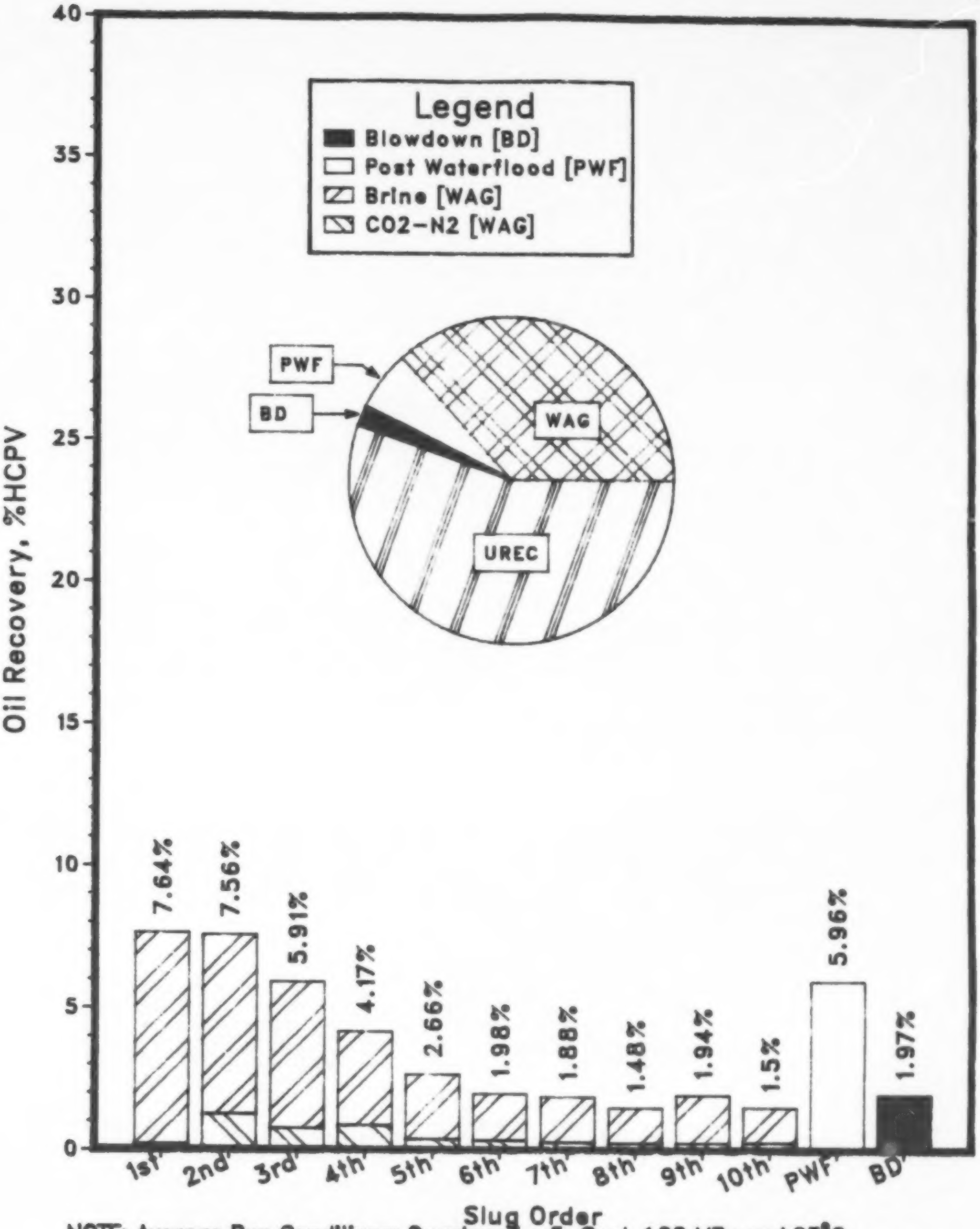
Figure F15 – Oil Recovery Distribution of Run 2DT1.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 40.14 %, k = 11.120 darcies, S_o = 89.51 %, S_{wc} = 10.49 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.150 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 9.99%
Total Oil Recovery = 44.8%

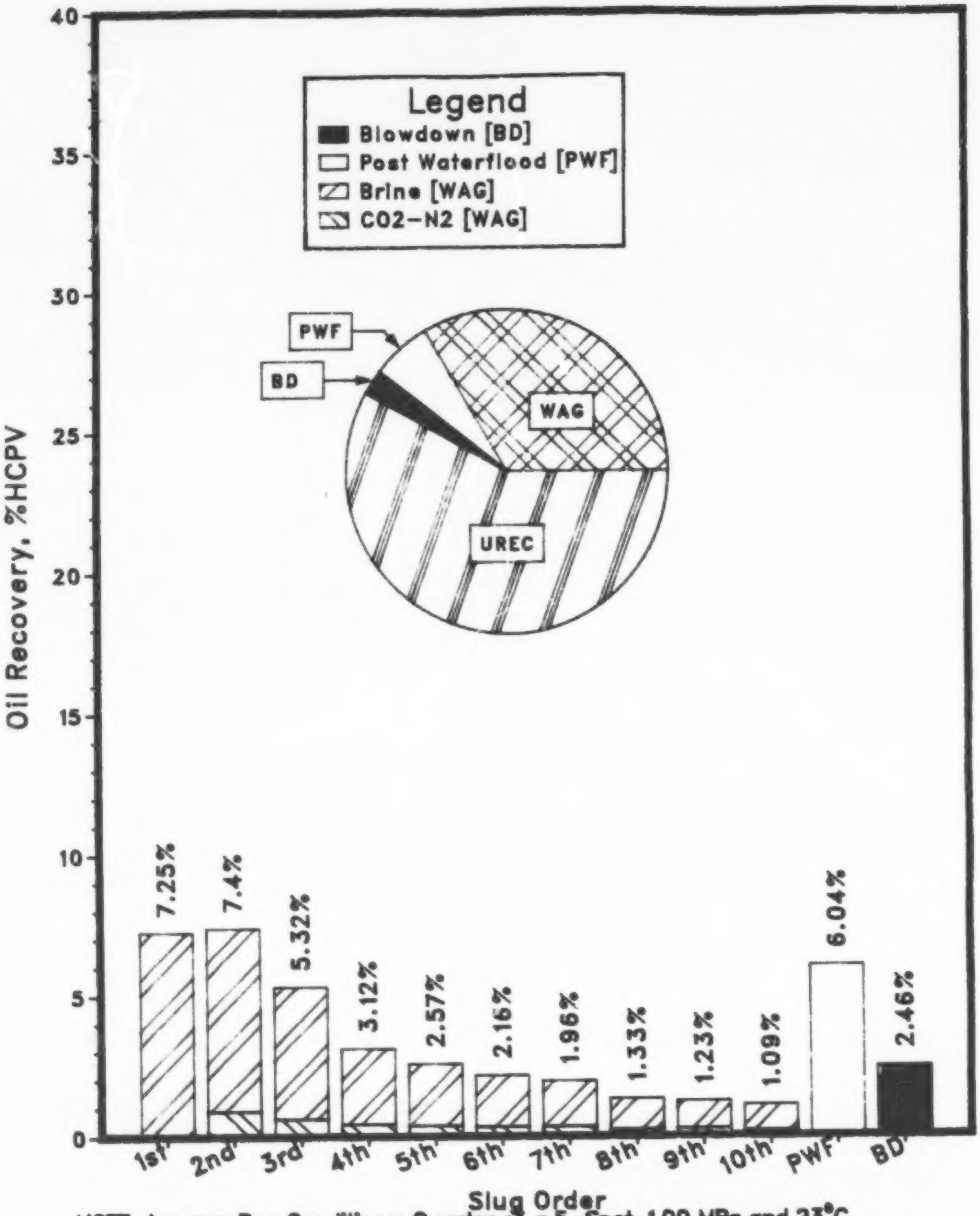
Figure F16 – Oil Recovery Distribution of Run 2DT2.



NOTE: Average Run Conditions: Quarter of a 5-Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 39.48 %, k = 11.220 darcies, S_o = 89.93 %, S_{wc} = 10.07 %

[0.20 HCPV CO2-N2 @ 1.0 MPa (0.148 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 15.00%
Total Oil Recovery = 44.7%

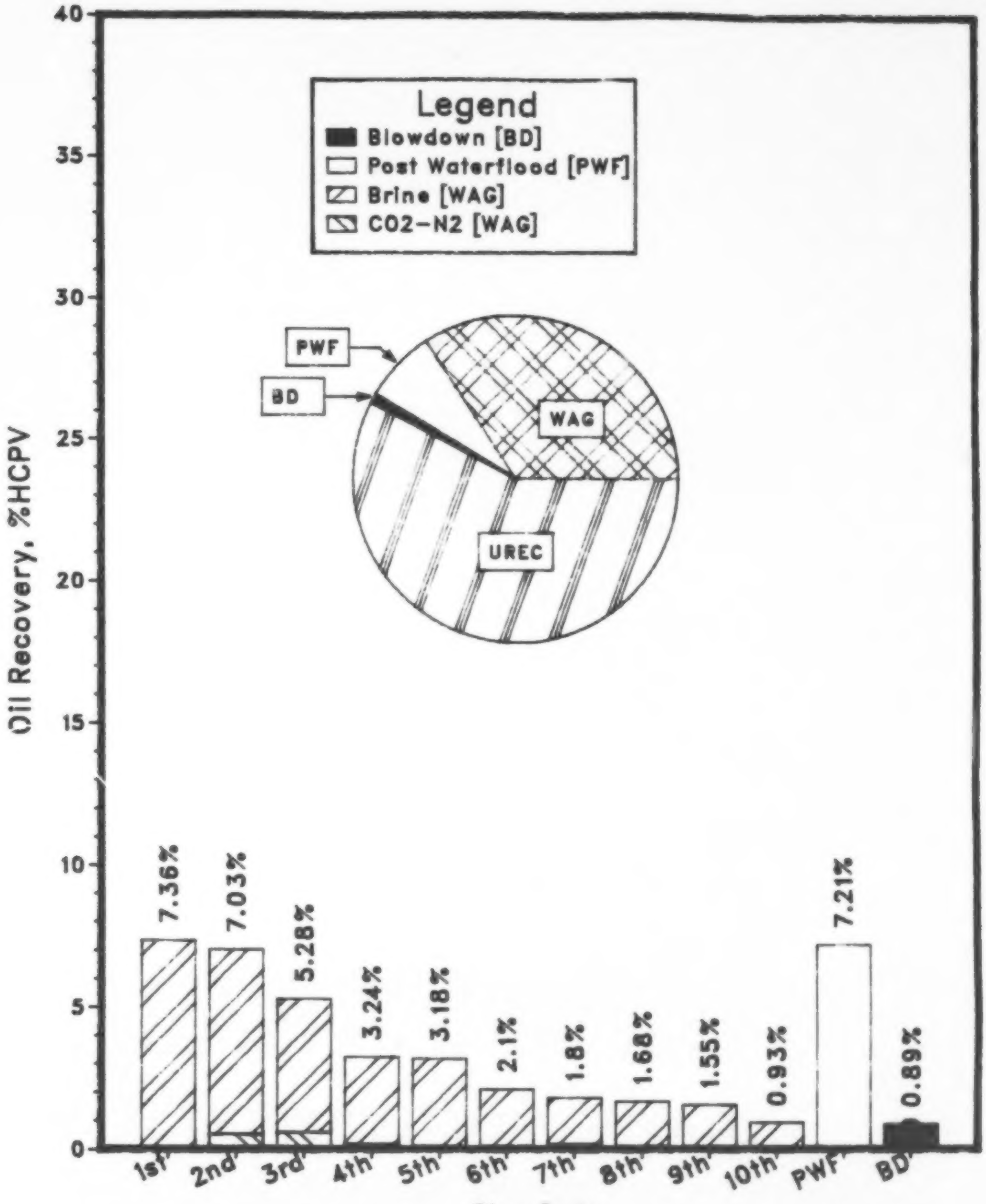
Figure F17 – Oil Recovery Distribution of Run 2DT3.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 37.16 %, k = 12.790 darcies, S_o = 90.14 %, S_{wc} = 9.860 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.139 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 20.00%
Total Oil Recovery = 41.9%

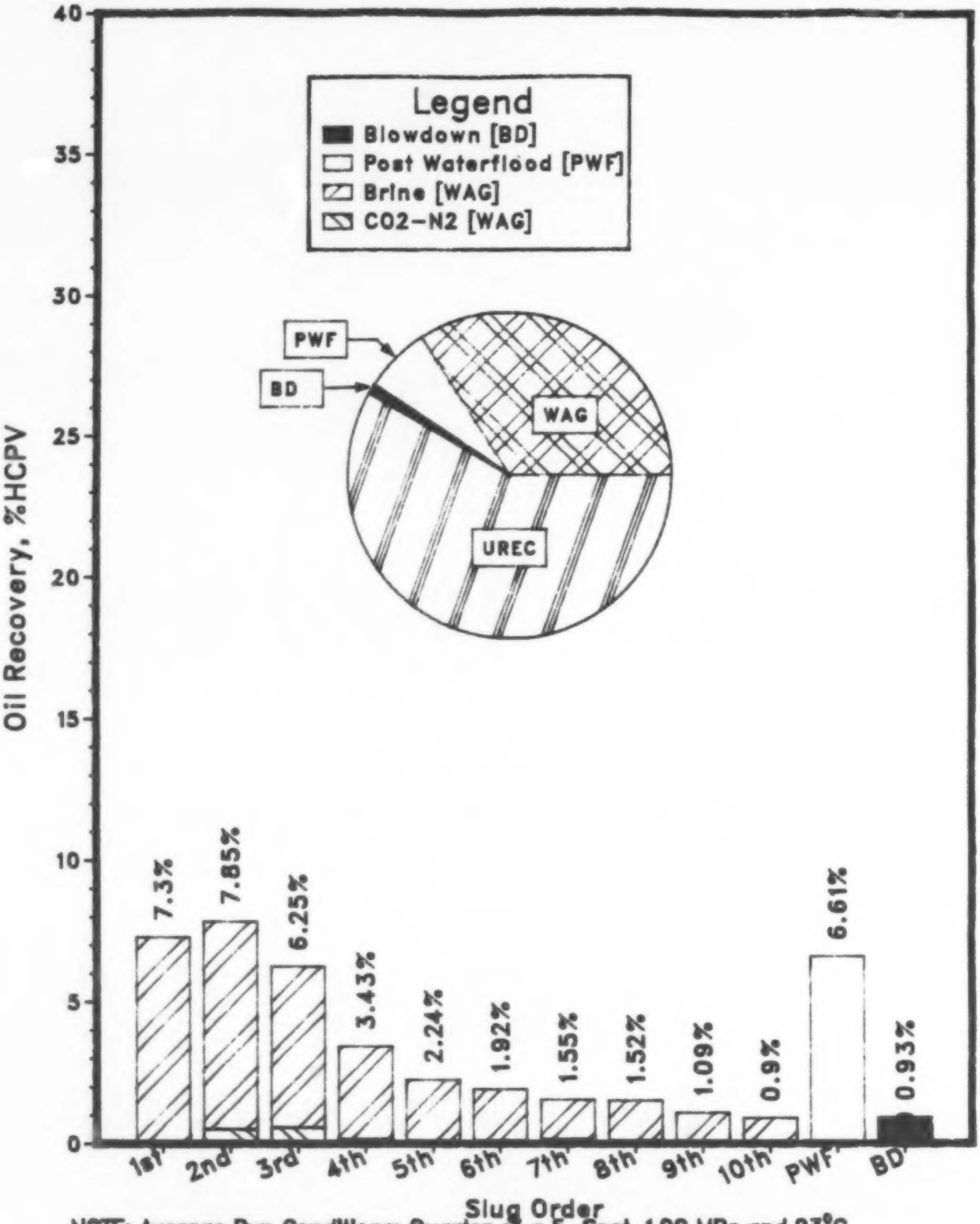
Figure F18 – Oil Recovery Distribution of Run 2DT4.



NOTE: Average Run Conditions: Quarter of a 5-Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 38.00 %, k = 14.040 darcies, S_o = 89.95 %, S_{wc} = 10.05 %

[0.20 HCPV CO2-N2 @ 1.0 MPa (0.142 g-mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 25.00%
Total Oil Recovery = 42.3%

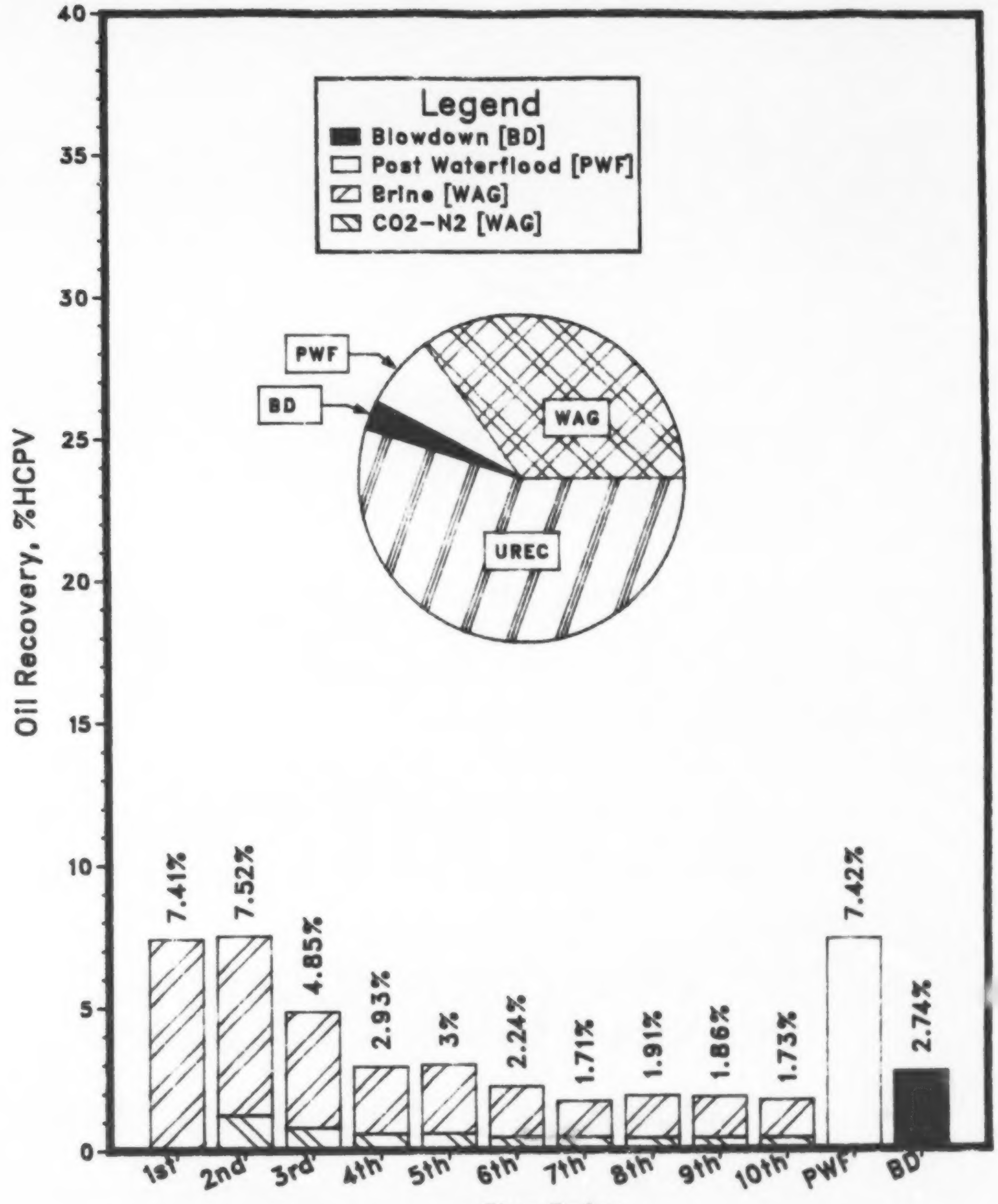
Figure F19 – Oil Recovery Distribution of Run 2DT5.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C
Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s
ϕ = 38.25 %, k = 12.960 darcies, S_o = 92.30 %, S_{wc} = 7.70 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.146 g–mol) 4:1 WAG, 10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 30.00%
Total Oil Recovery = 41.6%

Figure F20 – Oil Recovery Distribution of Run 2DT6.



NOTE: Average Run Conditions: Quarter of a 5–Spot, 1.00 MPa and 23°C

Model Parameters: Average Flow Velocity = 2.600 m/d, μ_o = 1058.0 mPa.s

ϕ = 40.44 %, k = 11.020 darcies, S_o = 88.98 %, S_{wc} = 11.79 %

[0.20 HCPV CO2–N2 @ 1.0 MPa (0.151 g–mol) 4:1 WAG,10 Slugs, DEAD OIL]
N2 Concentration in Mixture = 4.98%
Total Oil Recovery = 45.1%

Figure F21 – Oil Recovery Distribution of Run 2DT7.